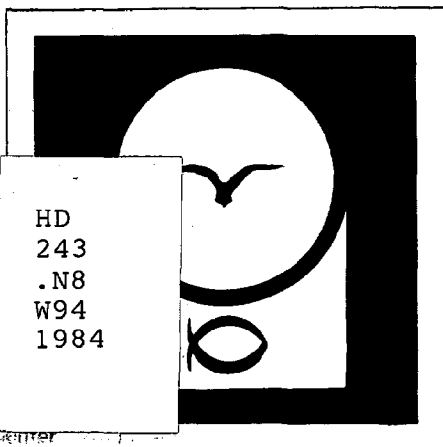
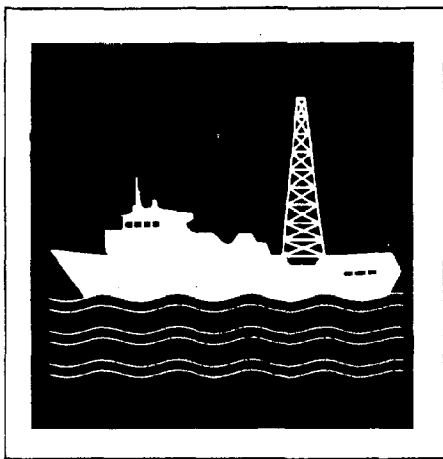
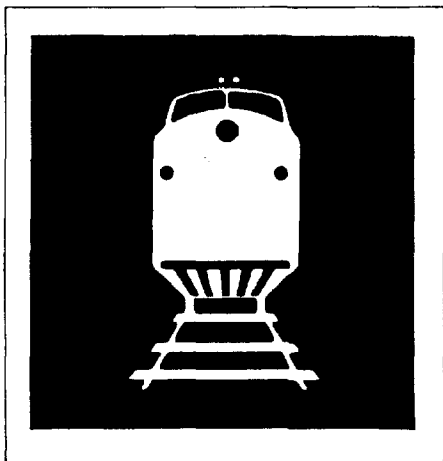


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# Oil and Gas Leasing of North Carolina's Submerged Lands

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INFORMATION CENTER

Charles D. Wyman  
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University of North Carolina at Chapel Hill

MARCH 1984

North Carolina  
Coastal Energy Impact Program  
Office of Coastal Management  
North Carolina Department of Natural Resources  
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OIL AND GAS LEASING OF NORTH CAROLINA'S  
SUBMERGED LANDS

by

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Center for Urban and Regional Studies  
University of North Carolina at Chapel Hill\*

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- Lee Mullis, Carolyn Jones, and Howard Cuppitt, of UNC-Chapel Hill, for their excellent work in typing this report and in preparing the maps in Chapter Two.

## SUMMARY OF MAJOR RECOMMENDATIONS

North Carolina General Statute §146-8 authorizes the state, upon request of the Department of Natural Resources and Community Development, to sell or lease mineral interests in state-owned submerged lands. Under this authority, the state has issued seven submerged lands oil and gas leases in the coastal area, the first in 1944 and the most recent in 1976. None resulted in any commercial find of oil or gas, and all have since expired.

This study reviews the state's options for exercising this authority with respect to oil and gas and presents a number of recommendations for the design of an oil and gas leasing program. The principal recommendations are:

1. A program for the development of public oil and gas resources in submerged lands should pursue, at a minimum, the following objectives:

- (a) to develop these oil and gas resources in an orderly and timely fashion;
- (b) to provide a fair market return to the state for the disposition of these resources;
- (c) to protect and enhance the natural and human environments;
- (d) to ensure that energy development is pursued within a context of orderly and balanced use and preservation of all coastal resources;
- (e) to minimize administrative burdens on government and industry, and maximize the predictability and credibility of the program;
- (f) to enhance competition and economic efficiency; and
- (g) to provide all sectors of government and the public at large with timely access to the decision-making process. Pp. 25-28.

2. Any exploration and development of public oil and gas resources in state-owned submerged lands should be undertaken by the private sector under lease from the state. Pp. 29-31.

3. Lessees should be chosen by competitive bidding. Pp. 31-35.
4. Areas to be considered for lease should be determined primarily by unsolicited applications from industry, though the state may consider unnominated tracts as it deems appropriate. Pp. 45-47.
5. To help ensure that environmental resources are adequately protected and that all legitimate concerns are identified and addressed, a three-phase procedure is recommended for review of all applications. First, a preliminary review would be conducted by the Division of Land Resources to determine such matters as the completeness of the application, the ownership of the land in question, and the status of the offshore lease market. Upon recommendation by Land Resources and concurrence of the Secretary, the application would then enter the second or substantive review phase. The review would be conducted either by the OCS Task Force or by a task force established by the Secretary and composed of NRCD and other state personnel. Uncertainties exist regarding future SEPA rules, but a hypothetical review procedure, assuming existing SEPA rules and an NRCD task force, is proposed (p. 54) and would include (1) review of the application to determine if it is or may be in the public interest; (2) if so, preparation of a Draft EIS, in most cases; (3) intradepartmental review of the Draft EIS, with changes as appropriate; (4) review of the Draft EIS by other state agencies, federal agencies, local governments, and the public, with one or more public hearings; and (5) after receipt of comments, a decision by the task force to reject the application or recommend a lease sale to the Secretary. In the final phase, after Secretarial approval the Final EIS and a proposed notice of sale would be prepared, the notice released for public comment, sent to the Department of Administration, Governor, and Council of State for approval, and finally issued as a final notice by the Secretary. Pp. 47-59.

6. A thorough environmental analysis and review should be conducted before the sale, not only to determine the advisability of the sale but also to ensure that all potential impacts are satisfactorily addressed by one of several vehicles of control available to the state, and to identify for the benefit of the bidders the major, likely requirements and restrictions to be imposed on lessees during the permitting stage. Pp. 63-69, 71-72.

7. Following review of each rejected application, the state should consider whether the facts of the case warrant promulgation of a temporary moratorium on leasing within certain areas. P. 65.

8. The state should continue to use an extension of the OCS grid into state waters to delineate block boundaries. The presumption should be that the 2304-ha. blocks will be offered individually for lease, but industry should be given the chance to demonstrate that tracts larger than a single block are needed to provide sufficient incentive for exploration and development. Pp. 73-77.

9. All questions of ownership interests, surface access rights, and liability for damages in areas being considered for lease should be resolved before leasing, if possible, and lease provisions should be used to establish the obligations of the various parties. Pp. 77-83.

10. All companies conducting oil and gas exploration in state waters should be required to obtain a permit from Land Resources and to provide the Division, upon request, with copies of survey data. The latter will require authorizing legislation. Pp. 88-93.

11. The lease sale should be conducted by sealed bidding. The bidding system used (the bidding variable and other, fixed terms) should be tailored to the characteristics of the individual sale, but should involve only a

single variable and at least initially should not include profit-share payments. Pp. 102-110.

12. The General Assembly should be requested to authorized NRCD to promulgate rules governing oil and gas operations on state lands.

Pp. 66-69.

## CHAPTER ONE

### Introduction

In 1937 the General Assembly approved legislation specifically authorizing the state to lease state bottomlands for mineral extraction, including oil and gas development.<sup>1</sup> Since then, beginning in 1944, there have been a total of seven oil and gas leases of the state's submerged lands; the last active lease expired in 1978. Under these and other leases, over 100 exploratory wells were drilled in the eastern coastal plain, including four in the waters of Pamlico and Albemarle Sounds. All have been dry. Yet large areas remain unexplored, and at least some geologists feel that hydrocarbon deposits of commercial size very possibly occur in eastern North Carolina.

Also since 1937, and particularly in the last dozen years, a growing understanding of the environmental and economic importance of the state's coastal resources has developed. This in turn has generated concern regarding the possible impacts of state oil and gas leasing of submerged lands, concern that was precipitated by lease applications in 1977 and 1980 and by the proposed leasing of tracts near Cape Lookout in federal OCS Lease Sale 56. In response to these events, officials in the Department of Natural Resources and Community Development concluded that a re-examination of the state's leasing program and procedures was needed, particularly to ensure that adequate environmental safeguards are in place and that the state receives fair market value for the sale of public resources. As part of this re-examination, a study of the state's leasing procedures was undertaken by the Center for Urban and Regional Studies at the University of North Carolina at Chapel Hill, with funding from the Coastal Energy Impact Program. This report presents the findings of that study.

The study has had three major objectives:

1. To review the issues surrounding leasing of submerged lands for oil and gas development in North Carolina;
2. To provide the results of this analysis to responsible state officials and other interested parties in a report that reviews the issues, examines alternative approaches, and makes specific recommendations for a leasing program; and
3. To draft regulations, as appropriate, that will implement the major findings of the study.

Three sources of information were consulted in reviewing leasing issues and in drafting recommendations. First, what relevant literature exists was

---

<sup>1</sup>North Carolina General Statutes §146-8. See Chapter 3 for the text and a discussion of the statute.

examined. This literature is most extensive for the federal OCS program, particularly with regards to obtaining fair market value and selecting appropriate bidding rules and methods. Second, a variety of people in North Carolina with interest and expertise in the subject were consulted. These included officials in various agencies of state government, researchers at several universities, and people representing several non-state-governmental interests. Finally, the study drew extensively on the experiences of the federal OCS program and leasing programs in other states. After contacting agencies in most coastal states, it was determined that six states have active submerged lands leasing programs: Alaska, California, Texas, Louisiana, Mississippi, and Alabama. These six programs and the OCS program were examined in depth, and their experience, together with occasional lessons from other states, is discussed at various locations throughout the report.

The study was concerned only with submerged lands, i.e., those lands lying below mean high water in the state's sounds, rivers, lakes, creeks, and offshore waters.<sup>2</sup> The vast majority of this submerged acreage occurs in the coastal area, and this is also where oil and gas interest in the state has historically been focused. For these reasons, and because the water bodies of the Piedmont and Mountains are sufficiently narrow that almost all drilling would be done on land, the discussion and recommendations below focus on the coastal area.

The study only touches on the difficult question of title to submerged lands. Literally thousands of private claims to property interests in submerged lands have been registered with the state. While the legitimacy of these claims is obviously of direct concern to any leasing program, the issue is too complicated to be dealt with here, and is being addressed by others. For the purposes of this study, it is assumed that title of lands being considered for lease rests with the state.

The report can be loosely organized in three main parts. Chapters 2 and 3 provide an introduction to the history and statutory environment of submerged lands oil and gas leasing in North Carolina. The discussion of leasing issues themselves and the study's recommendations for a leasing program are presented in Chapters 4 through 6. During the course of the study a substantial amount of information was assembled that, while not central to the problem of leasing program design, helps to establish the context of the problem or expands upon possible solutions. This material is presented in a series of appendices.

---

<sup>2</sup>As a result of the Submerged Lands Act of 1953 (43 U.S.C. §§1301-1315) and as confirmed by the Supreme Court (United States v. Maine et al., 420 U.S. 515 (1975)), the state's ownership of the seabed extends three geographical or nautical miles seaward of low mean water along the state's oceanfront coastline.

## CHAPTER TWO

### History of Oil and Gas Leasing and Drilling in North Carolina's Submerged Lands

The first oil well drilled in North Carolina was drilled in 1925 by Great Lakes Drilling Company (a local concern) on the eastern shore of Lake Ellis in Craven County.<sup>1</sup> Known as the Great Lakes No. 2 well, it was drilled to a depth of 2404 feet, where drilling was stopped when the backers became convinced crystalline basement rocks had been reached. The well was dry.

Since then, 122 other oil and gas wells have been drilled in North Carolina, 114 of them in the state's 20-county coastal zone (Figures 2-1 and 2-2). Although showings of oil or gas were reported from several wells, all but one were eventually abandoned as dry holes. (The most recent well, drilled during the summer of 1983 in Lee County, was still being tested at the time of writing). Four wells have been drilled in submerged lands: one in eastern Albemarle Sound, and three in northern and central Pamlico Sound.

The first oil and gas leases for state-owned bottomlands were let in 1944, one to the Coastal Plains Company of Kinston, and a second to Standard Oil Company of New Jersey. It is unclear what happened to the Coastal Plains lease, but no submerged lands drilling was undertaken. Under the terms of Standard's lease, the company was obligated to drill at least one well within 18 months of the signing. They eventually drilled two: one at Buxton in 1946 to a depth of 10,054 feet (the deepest yet drilled in the state; crystalline basement was reached at 9,853 feet below sea level), and a second in 1947 in Pamlico Sound 11 miles south of Wanchese, abandoned at 6,410 feet without reaching basement. Both were dry. Standard subsequently pulled out and relinquished its leases later that year.<sup>3</sup>

Since then, five other submerged lands oil and gas leases have been issued in North Carolina. The leased acreage, key terms, and histories of these seven leases are shown in Figure 2-3. The leases share several characteristic provisions. All were apparently negotiated individually with the prospective lessees, and competitive bidding was not used to determine and obtain market value. Each lease covered a very large area, commonly from

---

<sup>1</sup>Jasper L. Stuckey, North Carolina: Its Geology and Mineral Resources (Raleigh: N.C. Dept. of Conservation and Economic Development, 1965), p. 518.

<sup>2</sup>James C. Coffey, Exploratory Oil Wells in North Carolina, 1925-1976, Information Circular 22 (Raleigh: Geology and Mineral Resources Section, Division of Earth Resources, N.C. Dept. of Natural and Economic Resources, 1977), and files of the Division of Land Resources.

<sup>3</sup>Stuckey, North Carolina; "Prepare to Sink Drill for Oil in North Carolina," Charlotte Observer, 29 September 1944; "Oil Prospectors Discover Lots of Things But No Oil," Raleigh News and Observer, 8 June 1947.

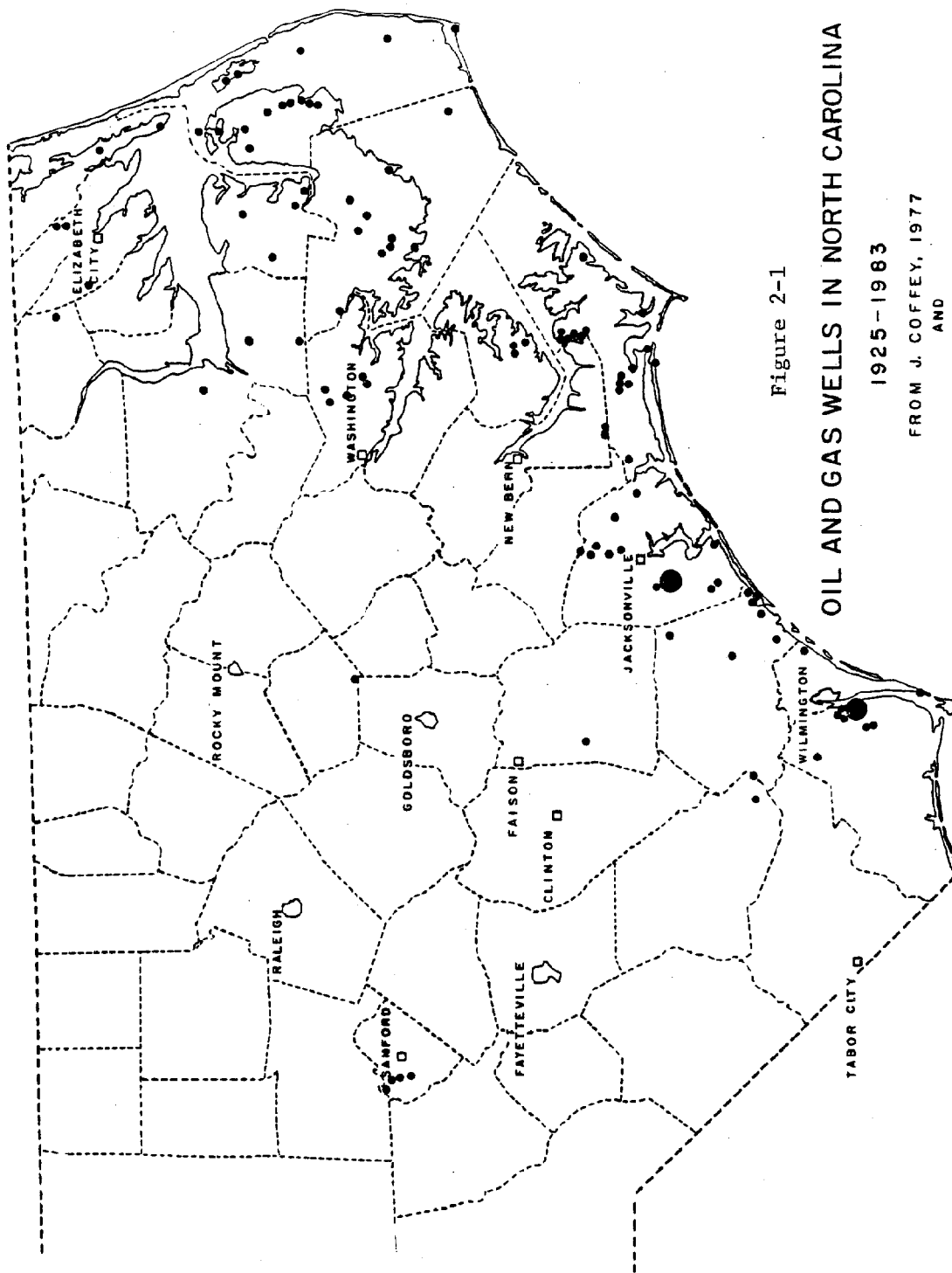


Figure 2-1

# OIL AND GAS WELLS IN NORTH CAROLINA

1925-1983

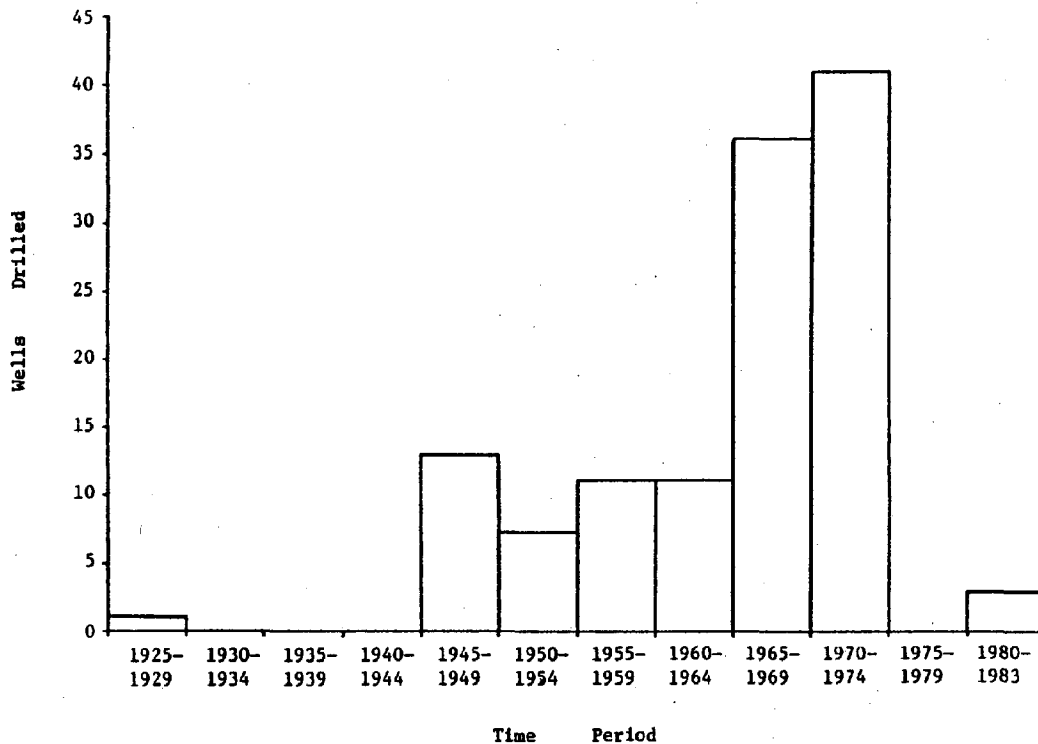
FROM J. COFFEY, 1977  
AND

FILES OF THE DIVISION OF LAND RESOURCES

## LEGEND

- 10 WELLS
- INDIVIDUAL WELLS

Figure 2-2. Exploratory Oil and Gas Wells Drilled in North Carolina by Period, 1925-1983.

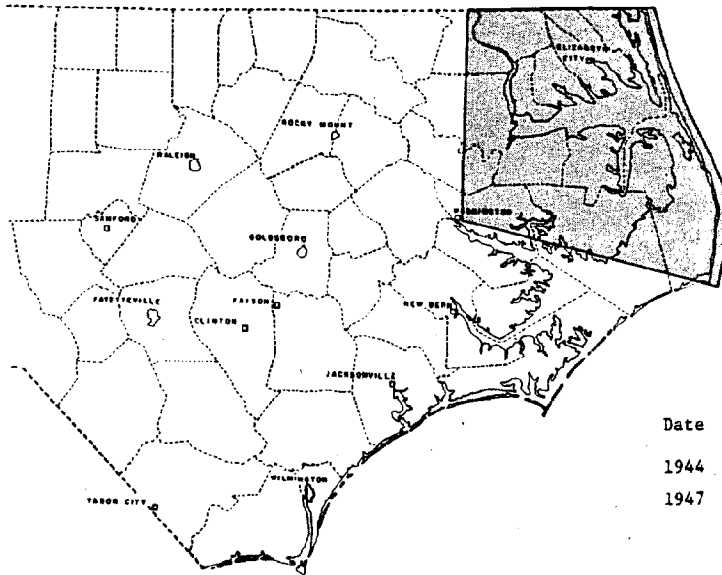


Data from James C. Coffey, Exploratory Oil Wells of North Carolina, 1925-1976, Information Circular 22 (Raleigh: N.C. Division of Earth Resources, Dept. of Natural and Economic Resources, 1977), and files of the Division of Land Resources.

several hundred thousand to over one million acres. From this area, the lessee could select tracts (ranging from 750,000 acres in the earliest lease to 5,760 acres in the most recent) to maintain under lease for as long as oil or gas was produced in paying quantities. A bonus payment was either not required or was a nominal one dollar, and annual rentals were not required except for acreage held until year ten under the special provisions of the 1944 and 1952 leases. In the last four leases, the lease could be extended for a period of time (25 years in three leases and 10 years in the fourth), without production, if the lessee met the biennial footage drilling requirement. Despite these similarities, the leases also evidence a progressive tightening of terms on the part of the state, most noticeably in the amount of acreage that could be held by a single producing well (reduced from 750,000 acres to 5,760), in the biennial footage drilling requirement (increased from 12,000 to 20,000 feet), and in the royalty paid to the state (from 1/8 to 1/6).

The last active lease of state bottomlands expired in 1978, and none have been issued since. In 1977, Mr. Carl Schmidt applied for a lease of 55,000

Figure 2-3. Submerged Lands Leases Issued in North Carolina, 1944-1976.



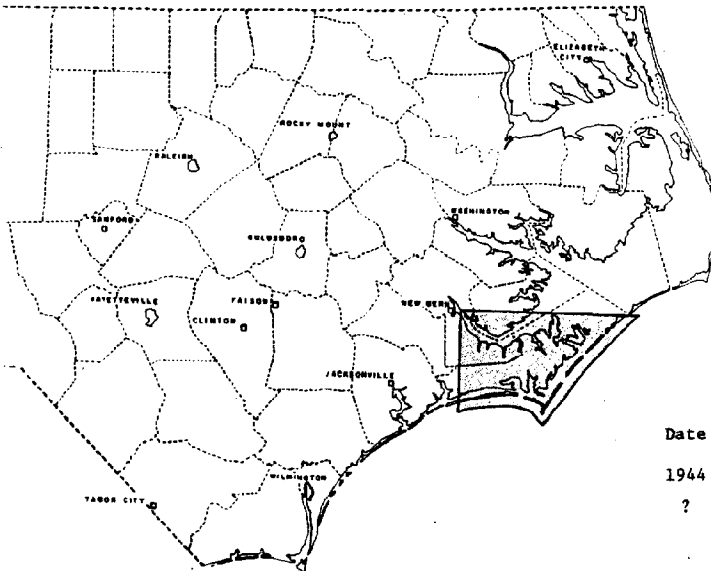
Date: 1944-1947

Issued to: Standard Oil Company of New Jersey

Major Terms: Bonus-none; Rentals-\$.10/acre on selected acreage (see below); Royalties-12.5%; Drilling must commence within 18 months and be pursued continuously (with lapses of only 120 days) up to 5 years, or lessees may select up to 75,000 acres per well drilled (750,000 acre maximum) and hold with \$.10/acre rental up to 10 years or hold with continuous drilling operations indefinitely; if oil or gas produced, up to 750,000 acres of the area then under lease may be held for as long as oil or gas produced in paying quantities.

History:

Date	Lease Transaction	Royalty Reserved by Lessor/Assignor
1944	Issued to Standard Oil of N.J.	12.5%
1947	Lease relinquished	



Date: 1944-?

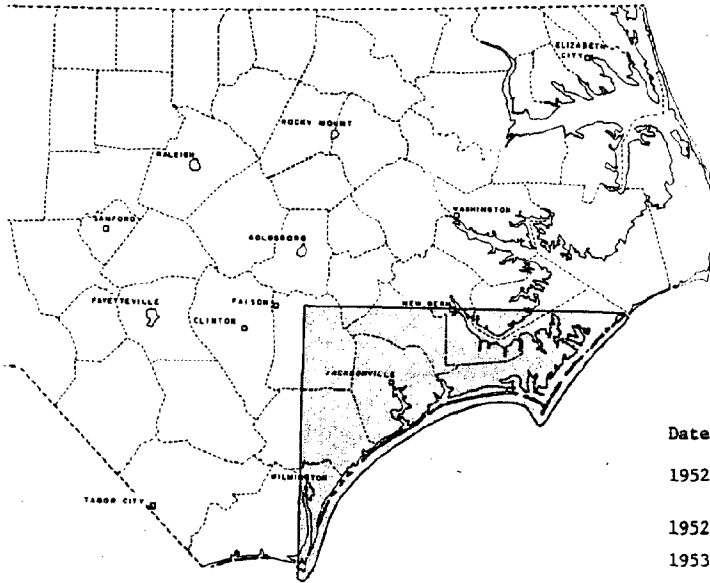
Issued to: Coastal Plains Company

Major Terms: Bonus-none; Rentals-\$.10/acre on selected acreage (see below); Royalties-12.5%; Drilling must commence within 18 months and be pursued continuously (with lapses of only 120 days) up to 5 years, or lessee may select up to 75,000 acres per well drilled (375,000 acre maximum) and hold with \$.10/acre rental up to 10 years or hold with continuous drilling operations indefinitely; if oil or gas produced, up to 375,000 acres of the area then under lease may be held for as long as oil or gas produced in paying quantities.

History:

Date	Lease Transaction	Royalty Reserved by Lessor/Assignor
1944	Issued to Coastal Plains Co.	12.5%
?	Cancelled/relinquished	

Figure 2-3. Submerged Lands Leases Issued in North Carolina, 1944-1976.  
(Continued)



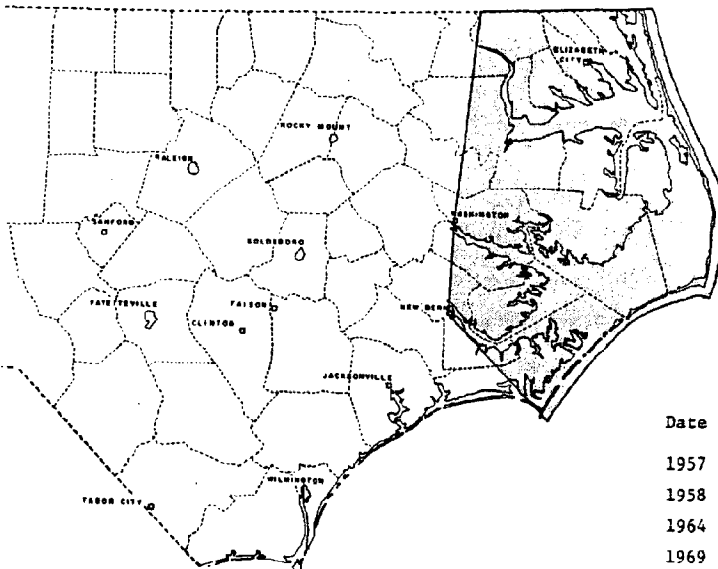
Date: 1952-1953?

Issued to: Matt H. Allen, E.R. Buchan, and Ely J. Perry, Trustees for Coastal Plains Company

Major Terms: Bonus-none; Rentals-\$.10/acre on selected acreage (see below); Royalties-12.5%; Drilling must commence within 4 months and be pursued continuously (with lapses of only 120 days) up to 5 years, or lessees may select up to 75,000 acres per well drilled (375,000 acre maximum) and hold with \$.10/acre rental up to 10 years or hold with continuous drilling operations indefinitely; if oil or gas produced, up to 375,000 acres currently under lease may be held for as long as oil or gas produced in paying quantities.

History:

Date	Lease Transaction	Royalty Reserved by Lessor/Assignor
1952	Issued to Matt H. Allen, E.R. Buchan, and Ely J. Perry	12.5%
1952	Assigned to E.T. Burton, Jr.	?
1953?	Expired for failure to drill	



Date: 1957-1977

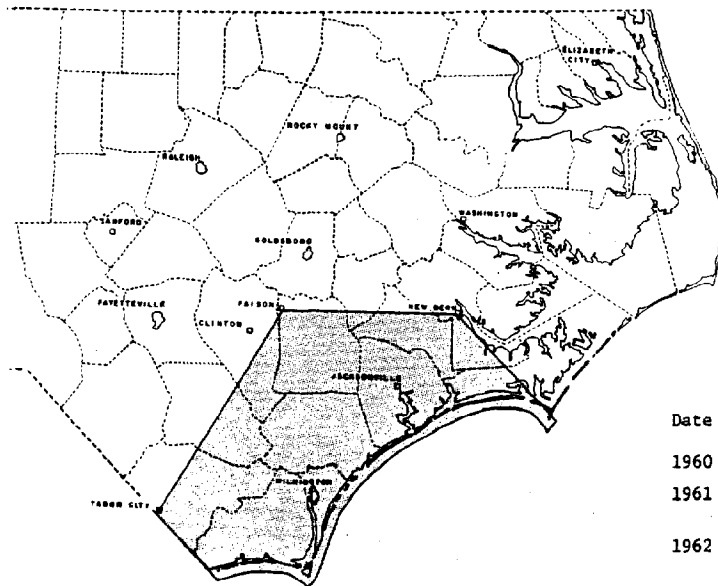
Issued to: J.E. Fitz-Patrick, of Fort Worth, Texas

Major Terms: Bonus-\$1; Rentals-none; Royalties-12.5%; 12,000 feet of drilling required every 2 years to renew lease, up to 25 year maximum; if oil or gas found in commercial quantities, tracts of 75,000 acres each may be selected and held as long as oil or gas produced from them in paying quantities.

History:

Date	Lease Transaction	Royalty Reserved by Lessor/Assignor
1957	Issued to J.E. Fitz-Patrick	12.5%
1958	Assigned to Coastal Plains Oil Co.	3.5%
1964	Assigned to Socony Mobil Oil Co.	-
1969	Assigned to Coastal Plains Oil Co.	-
1971	Assigned to Cities Service Co.	9% + 12.5% (up to \$1.2 million)
1977	Cancelled for failure to drill	

Figure 2-3. Submerged Lands Leases Issued in North Carolina, 1944-1976.  
(Continued)



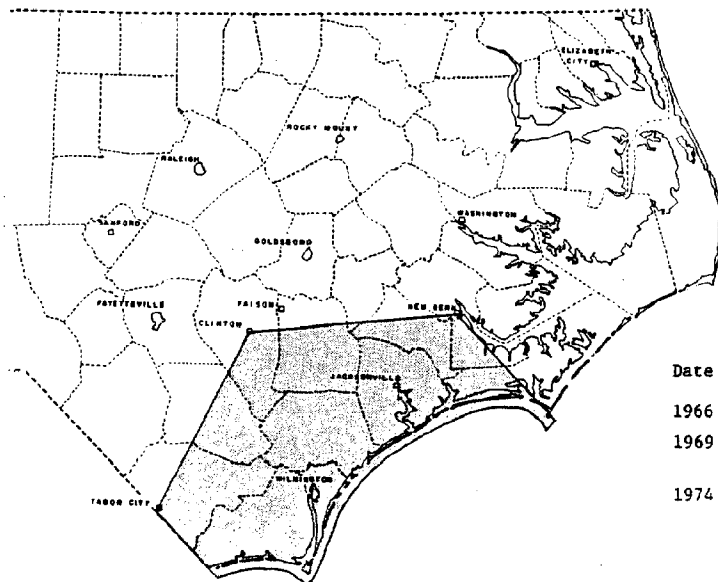
Date: 1960-1962

Issued to: Roderick A. Stamey, of Houston, Tx

Major Terms: Bonus-\$1; Rentals-none; Royalties-12.5%; 12,000 feet of drilling required every 2 years to renew lease, up to 25 year maximum; if oil or gas found in commercial quantities, tracts of 75,000 acres each may be selected and held as long as oil or gas produced from them in paying quantities.

History:

Date	Lease Transaction	Royalty Reserved by Lessor/Assignor
1960	Issued to Roderick A. Stamey	12.5%
1961	Assigned to Atlantic Coast Explorations, Inc.	?
1962	Expired for failure to drill	



Date: 1966-1976

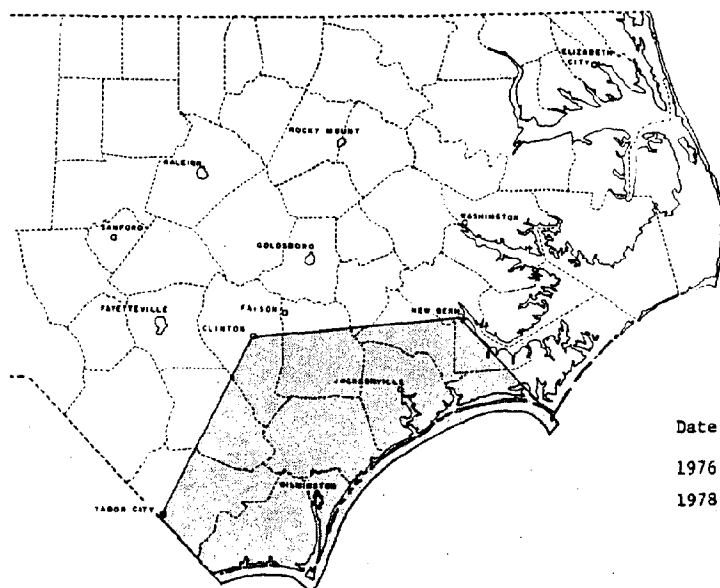
Issued to: North Carolina Oil and Gas Company

Major Terms: Bonus-\$1; Rentals-none; Royalties-12.5%; 20,000 feet of drilling required every 2 years to renew lease, up to 25 year maximum; if oil or gas found in commercial quantities, tracts of 7,500 acres each may be selected and held as long as oil or gas produced from them in paying quantities.

History:

Date	Lease Transaction	Royalty Reserved by Lessor/Assignor
1966	Issued to N.C. Oil and Gas Co.	12.5%
1969	Assigned to Colonial Oil and Gas Co.	5.0%
1974	65% interest assigned to F.W. Carr of Southampton, N.Y.; 10% interest assigned to K.H. Schmidt of San Antonio, Texas	-
1975	Carr assigned his 65% interest to Schmidt	0.5%
	Colonial assigned remaining 25% interest to Schmidt	0.5%
	Schmidt assigned his 100% interest to The Anschutz Corp.	1.0%
1976	Lease superseded by new lease to The Anschutz Corp.	

Figure 2-3. Submerged Lands Leases Issued in North Carolina, 1944-1976.  
(Continued)



Date: 1976-1978

Issued to: The Anschutz Corp. (as consolidation of existing state leases of submerged lands and fast lands held by Anschutz)

Major Terms: Bonus-\$1; Rentals-none; Royalties-16.67%; 20,000 feet of drilling required every 2 years to renew lease, up to 10 year maximum, with one foot credit available for every \$10 of other exploratory work; if oil or gas found in commercial quantities, tracts 3 miles by 3 miles (5760 acres) each may be selected and held as long as oil or gas produced from them in commercial quantities.

History:

Date	Lease Transaction	Royalty Reserved by Lessor/Assignor
1976	Issued to The Anschutz Corp.	16.67%
1978	Cancelled for failure to drill	

acres in the Cape Hatteras area, but the request was dropped upon the death of the applicant in 1978. During review of the lease proposal, however, the state initiated several major changes in its leasing program. The federal OCS grid, consisting of lease blocks roughly three miles square, was extended into state waters. The state declared its intention to lease much smaller acreages than in the past, using these lease blocks, and to eliminate the practice of selecting areas within the lease boundaries to be held by production. A new lease form was drafted that, among other things, provided for delay rentals and limited the primary lease term to five years, with extension possible only through production or continuous drilling. These changes brought the state more in line with current industry practice.

In 1980, a request was received from Mr. Shirley Murphy to lease 35,160 acres in the Alligator River and Pamlico Sound and to acquire an option to lease an additional 2,000,000 acres of submerged lands. The request was considered favorably during the early stages of review, but was deferred when formulation of state policy on OCS lease sales made apparent the need for a more consistent approach to offshore leasing in state and federal waters.

## CHAPTER THREE

### Legislation

State and federal laws covering a broad array of topics will govern the course of oil and gas development on North Carolina's submerged lands. Any attempt to design a leasing program for North Carolina must begin with an understanding of what these laws permit and require.

Laws authorizing mineral leasing of state submerged lands and laws specifically regulating oil and gas activities in North Carolina are described below. The principal environmental protection statutes are also briefly reviewed; more detailed descriptions of these and other applicable statutes covering such topics as navigational rights, business and employment practices, and historic and cultural preservation may be found in Appendix E. Tables 3-1 and 3-2 at the end of the chapter summarize the statutes and permit programs that will govern oil and gas development in coastal waters.

#### 3.1 Powers to Lease

While lands under the interior waters of a state (e.g., Pamlico Sound) have always been under state jurisdiction, state and federal authorities for many years disputed control of the lands seaward of the coastline. Congress partly resolved the problem in 1953 with passage of the Submerged Lands Act.<sup>1</sup> This Act revived the jurisdiction historically granted to coastal states, determining that the zone three miles seaward of the mean low water mark is rightfully under state, rather than federal, control. It renewed in the states the right to "manage, administer, lease, develop, and use" these submerged lands and the underlying natural resources. The Act did retain some federal jurisdiction over matters of commerce, navigation, national defense, and international affairs. State claims to the seabed beyond three miles were extinguished in 1975 by the Supreme Court in United States v. Maine.<sup>2</sup>

Disposition of interests in state-owned submerged lands is governed by N.C.G.S. §146-3 through §146-15. These statutes forbid the sale of submerged lands but authorize their leasing. Section 146-8 specifically gives the state authority to sell, lease, or otherwise dispose of mineral deposits on state submerged lands, or to lease these lands for the excavation and removal of minerals. The full text of this section, as most recently amended in 1977, is:

The State, acting at the request of the Department of Natural Resources and Community Development, is fully authorized and empowered to sell, lease, or otherwise dispose of any and all mineral deposits

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<sup>1</sup>43 U.S.C. §§1301-1315.

<sup>2</sup>420 U.S. 515 (1975).

belonging to the State which may be found in the bottoms of any sounds, rivers, creeks, or other waters of the State. The State, acting at the request of the Department of Natural Resources and Community Development, is authorized and empowered to convey or lease to such person or persons as it may, in its discretion, determine, the right to take, dig, and remove from such bottoms such mineral deposits found therein belonging to the State as may be sold, leased, or otherwise disposed of to them by the State. The State, acting at the request of the Department of Natural Resources and Community Development, is authorized to grant to any person, firm, or corporation, within designated boundaries for definite periods of time, the right to such mineral deposits, or to sell, lease, or otherwise dispose of same upon such other terms and conditions as may be deemed wise and expedient by the State and to the best interest of the State. Before any such sale, lease, or contract is made, it shall be approved by the Department of Administration and by the Governor and Council of State.

Any sale, lease, or other disposition of such mineral deposits shall be made subject to all rights of navigation and subject to such other terms and conditions as may be imposed by the State.

The net proceeds derived from the sale, lease, or other disposition of such mineral deposits shall be paid into the treasury of the State, but the same shall be used exclusively by the Department of Natural Resources and Community Development in paying the costs of administration of this section and for the development and conservation of the natural resources of the State, including any advertising program which may be adopted for such purpose, all of which shall be subject to the approval of the Governor, acting by and with the advice of the Council of State.<sup>3</sup>

### 3.2 Oil and Gas Activities

The most important state legislation governing the conduct of oil and gas activities is the North Carolina Oil and Gas Conservation Act.<sup>4</sup> Part 1 of the Act requires every driller to register with the Department of Natural Resources and Community Development (NRCD) and file a \$5000 bond to assure satisfactory plugging of each well. Upon a well's completion or abandonment, the operator must file with NRCD a complete log of the drilling and development of the well.

Part 2 of the Act contains provisions for prevention of waste, establishment of drilling units, regulation of production, and notification to NRCD prior to any drilling, abandonment, or plugging of wells. The more detailed regulations for drilling, casing, and plugging of wells to prevent escape, intrusion, pollution, drainage, blowouts, caving, seepage, and well-crowding are located at 15 NCAC 5C .0001-.0028. Also under the authority of

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<sup>3</sup>The Council of State is an "executive board" consisting of all the elected statewide officials in the Executive Branch. This group includes the Governor, the Lieutenant Governor, the Secretary of State, the State Auditor, the State Treasurer, the Superintendent of Public Instruction, the Attorney General, and the Commissioners of Agriculture, Labor and Insurance.

<sup>4</sup>N.C. Gen. Stat. §113-378 to §113-415.

Part 2, the Department has promulgated rules regulating seismic exploration.<sup>5</sup> Permits are required for all seismic work, and where wildlife will be affected, the Secretary must consult with the North Carolina Wildlife Resources Commission and the U.S. Fish and Wildlife Service.

For the most part, pipeline construction and operation are regulated under state or federal law, depending on whether the pipeline is designated as an intrastate or interstate line. The major federal authorities are (1) the Natural Gas Act,<sup>6</sup> which gives the Federal Energy Regulatory Commission authority to issue "certificates of public convenience and necessity" granting a right of eminent domain for projects involving the sale or transportation of natural gas in interstate commerce, and (2) the Natural Gas Pipeline Safety Act of 1968<sup>7</sup> and the Hazardous Liquid Pipeline Safety Act of 1979,<sup>8</sup> under which authority the U.S. Department of Transportation has issued regulations governing the design, construction, operation, and maintenance of interstate oil and gas pipelines. The corresponding state authority is the N.C. Public Utilities Act;<sup>9</sup> §62-110 requires certificates of public convenience and necessity to be acquired for intrastate oil and gas lines, §62-192 confers the power of eminent domain on these lines, and §62-50 provides for the regulation of gas pipeline construction and operation practices, under which the Public Utilities Commission has adopted the federal standards almost verbatim.

Finally, under N.C.G.S. §143-215.100 et seq., a permit is required from the Secretary of Natural Resources and Community Development for construction of an oil refinery. The Secretary may deny a permit upon finding that the facility would have substantial adverse effects on wildlife, fisheries, or a public park, forest, or recreation area, and may require whatever measures are necessary to prevent oil discharges.

### 3.3 Environmental Protection

Although there are a host of applicable environmental statutes and regulations, five statutes will provide the bulk of environmental protection for any submerged lands considered for leasing by the state. These are:

1. The National Environmental Policy Act.<sup>10</sup> This act requires that an Environmental Impact Statement (EIS) be prepared for any action under federal control and responsibility "significantly affecting the quality of the human environment." NEPA has been held to apply to projects requiring federal

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<sup>5</sup>15 NCAC 5C.

<sup>6</sup>15 U.S.C. §§717-717w.

<sup>7</sup>49 U.S.C. §§1671-1686.

<sup>8</sup>49 U.S.C. §§2001-2014.

<sup>9</sup>N.C. Gen. Stat. §62-1 to §62-333.

<sup>10</sup>42 U.S.C. §§4321-4347.

permits or licenses (such as Section 10 and 404 permits, needed for offshore drilling), but not to those merely requiring federal review of an application.

2. The North Carolina State Environmental Policy Act (SEPA).<sup>11</sup> A state EIS is required under SEPA for "actions involving expenditure of public moneys for projects and programs significantly affecting the quality of the environment of this state." Interpretations of the Act have tended to limit the types of projects to which SEPA is applicable; the relevance of this statute to submerged lands oil and gas leasing is discussed in Chapter Five.

3. The Federal Water Pollution Control Act.<sup>12</sup> Four provisions of this Act are significant. Section 402 establishes the National Pollutant Discharge Elimination System (NPDES), under which a permit (now administered by the state's Division of Environmental Management) will be required for any discharges of pollutants from drilling barges, ships, or platforms. Section 401 requires that every proposed federally licensed project, including exploratory and development drilling, be certified by the state that it will not violate state water quality standards. Permits for the discharge of dredge and fill materials into navigable waters are required under Section 404; this provision is administered by the Corps of Engineers in conjunction with the Section 10 program (below), and would apply to most oil and gas activities in shallow, estuarine waters. Finally, Section 311 establishes liability for oil spills and provides for federal clean-up action, as outlined in National, Regional, and Local Contingency Plans, should the owner or operator fail to respond properly.

4. The Rivers and Harbors Act of 1899.<sup>13</sup> Section 10 of this Act requires a permit from the Corps of Engineers for any structure or other impediment to navigation in navigable waters. Most facilities operating below the mean high tide line, including drilling operations, storage tanks, and pipelines, will require a permit. The Corps must consider environmental factors in its Sections 10 and 404 permit reviews, as well as the comments solicited from other agencies and the public.

5. The North Carolina Coastal Area Management Act (CAMA).<sup>14</sup> Under CAMA, a major development permit from the Coastal Resources Commission will be required for oil and gas drilling operations in submerged lands. The standards for issuance are listed in Appendix E, and require that the proposed action be compatible with state guidelines for estuarine Areas of Environmental Concern adopted under CAMA, approved local land use plans, general policy guidelines for the coastal area, and the specific standards of N.C.G.S. §113-229(e) and §113-230. Unless approval of a plan of operations is required (see Chapter Six), the CAMA and NPDES permits will be the state's principal instruments for environmental protection once the lease is issued.

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<sup>11</sup>N.C. Gen. Stat. §113A-1 to §113A-10.

<sup>12</sup>33 U.S.C. §§1251-1367.

<sup>13</sup>33 U.S.C. §403.

<sup>14</sup>N.C. Gen. Stat. §113A-100 to §113A-128.

Table 3-1  
Legislation Affecting Oil and Gas Activities in Submerged Lands

<u>Name</u>	<u>Citation</u>	<u>Significance</u>
<u>FEDERAL</u>		
Submerged Lands Act of 1953	43 U.S.C. §1301 et seq.	State jurisdiction over the seabed extends 3 miles from shore
Natural Gas Pipeline Safety Act	49 U.S.C. §1671 et seq.	Design, construction, and operation standards for interstate pipelines
National Environmental Policy Act	42 U.S.C. §4321 et seq.	Requires environmental impact statements for major federal actions
Federal Water Pollution Control Act	33 U.S.C. §1251 et seq.	Establishes standards and permit program for polluting discharges
Clean Air Act	42 U.S.C. §7401 et seq.	Sets National Ambient Air Quality Standards and requires permits for some emissions
Clean Water Act	33 U.S.C. §1321	Establishes liability for oil spills and provides for federal clean-up efforts through a National Contingency Plan
Comprehensive Environmental Response, Compensation and Liability Act	42 U.S.C. §9605	Encourages State and Local oil spill contingency plan(s)
Coastal Zone Management Act of 1972	16 U.S.C. §1451	National policy for protection of coastal areas; provides for state and local planning and management, and consistency of federal actions with state programs
Endangered Species Act of 1973	16 U.S.C. §1531	Requires that federal action not jeopardize listed species

Table 3-1 (Continued)

## Legislation Affecting Oil and Gas Activities in Submerged Lands

<u>Name</u>	<u>Citation</u>	<u>Significance</u>
Fish and Wildlife Coordination Act	16 U.S.C. §661 et seq.	Wildlife conservation must be considered in federal actions
Marine Mammal Protection Act	16 U.S.C. §1361	Illegal to "take" mammals in U.S. waters
Ports and Waterways Safety Act	33 U.S.C. §§1221-1232	Gives Coast Guard responsibility for port and navigational safety
Rivers and Harbors Act of 1899	33 U.S.C. §401 et seq.	Regulates construction in navigable waters
National Gas Policy Act	15 U.S.C. §3301 et seq.	Sets ceiling prices for natural gas in interstate commerce
National Historic Preservation Act of 1966	16 U.S.C. §470f	Requires that places on or eligible for National Register of Historic Places be considered in federal actions
STATE:		
Disposition of unallocated state lands statutes	N.C.G.S. §146-3 to §146-15	Governs sale and leasing of unallocated state lands, including submerged lands
Oil and Gas Conservation Act	N.C.G.S. §113-378 to §113-415	Provides for regulation of oil and gas drilling and production in N.C.
Public Utilities Act	N.C.G.S. §62-1 to §62-333	Regulates intrastate oil and gas pipelines
State Environmental Policy Act	N.C.G.S. §113A-1 to §113A-10	Mandates preparation of State Environmental Impact Statements

Table 3-1 (Continued)

## Legislation Affecting Oil and Gas Activities in Submerged Lands

<u>Name</u>	<u>Citation</u>	<u>Significance</u>
	N.C.G.S. §143B-437	Requires impact assessment by Commerce and NRCB of new or expanding industry
Oil Pollution and Hazardous Substances Control Act	N.C.G.S. §143-215.75 to §143-215.102	Provides for liability and state clean-up of oil spills and regulation of oil refineries and oil terminal facilities
Water Use Act of 1967	N.C.G.S. §143-215.11 to §143-215.22	Establishes state policy for water conservation and regulatory program in capacity use areas
Coastal Area Management Act	N.C.G.S. §113A-100 to §113A-128	Establishes state planning and management program for coastal areas, including permits for activities in Areas of Environmental Concern
Sedimentation Pollution Control Act	N.C.G.S. §113A-50 to §113A-66	Establishes erosion and sedimentation control program
	N.C.G.S. §76-40	Regulates placement of refuse and structures in navigable waters under state jurisdiction
Dredge and Fill Act	N.C.G.S. §113-229	Regulates dredge and fill activities in state waters
Water pollution control statutes	N.C.G.S. §143-211 to §143-215.9	Regulates discharge of water pollutants
Air pollution control statutes	N.C.G.S. §143-215.105 to §143-215.114	Regulates emission of air pollutants

Table 3-1 (Continued)

Legislation Affecting Oil and Gas Activities in Submerged Lands

<u>Name</u>	<u>Citation</u>	<u>Significance</u>
Corporation Income Tax Act	N.C.G.S. §105-130 to §105-130.26	Provides state income tax deductions for health, safety, and pollution control devices
Archives and History Act	N.C.G.S. §121-12(a)	Requires that impacts on sites listed in National Register of Historic Places be considered before state actions are taken
	N.C.G.S. §121-22 to §121-28	Invests Department of Cultural Resources with responsibility and ownership of shipwrecks and underwater artifacts

TABLE 3-2

## Permits, Licenses, and Certifications for Oil and Gas Activities in Submerged Lands

Permit	Description	Phases Required				Admin- istering Agency	Statutory/ Regulatory Authority
		Required					
		R=Likely	P=Possible	I	II III IV		
STATE:							
Geophysical Exploration Permit	Required before seismic exploration using explosives	R				DLR	N.C.G.S. §113-391; 15 NCAC 5C
*CAMA Major Development Permit	For any major development in an area of environmental concern	R	L	L		OCM	N.C.G.S. §113A-118; 15 NCAC 7J
Permit to drill exploratory oil or gas wells	Required before the drilling of each exploratory well	R	L			DLR	N.C.G.S. §113-378; 15 NCAC 5D
*Dredge and Fill Permit	For any project involving dredging or filling in estuaries	L	L			OCM	N.C.G.S. §113-229; 15 NCAC 7J
Air Quality Permit	For any air contaminant source with listed emission quality standard	L	L	L		OCM	N.C.G.S. §143-215.108; 15 NCAC 2D,H .0600
*Easement to Fill	For filling activities where land is raised above high water mark	P	P			DOA	N.C.G.S. §146-6; 1 NCAC 6B .0500-0512

Table 3-2 (Continued)

Permit	Description	PHASES REQUIRED				Admin- istering Agency	Statutory/ Regulatory Authority	
		R=Required						
		L=Likely						
		P=Possible						
<u>I</u>	<u>II</u>	<u>III</u>	<u>IV</u>					
Wastewater Non-Discharge Permit	For systems with over 3,000 gallon capacity not discharging to surface waters	P	P	P	P	DEM	N.C.G.S. §143-215.1, 215.3; 15 NCAC 2H .0200	
Solid Waste Disposal Site Permit	For establishing and operating disposal facilities and incenerators	P	P	P	P	DHS	N.C.G.S. §130-166.18(a); 10 NCAC 10G	
Oil Refinery Facility Permit	For construction of refineries				R	DEM	N.C.G.S. §143-215.100; 15 NCAC 1F	
Oil Terminal Facility Registration	For construction of any facility for transporting, storing, or processing oil		R	R	R	DEM	N.C.G.S. §143-215.96;	
Water Use Permit	For major uses of sur- face and groundwater in capacity use areas		P	P	P	DEM	N.C.G.S. §143-215.15 15 NCAC 2E	
Sedimentation Control Plan	For land disturbing activities on tracts bigger than one acre		P	P	P	L	DLR	N.C.G.S. 113A-54; 15 NCAC 4
Environmental Impact Assessment	For any new or expanding industry	P	P	P	P	P	DOC/ NRCD	N.C.G.S. §143B-437

Table 3-2 (Continued)

Permit	Description	PHASES REQUIRED				Admin- istering Agency	Statutory/ Regulatory Authority
		R=Required					
		L=Likely					
		P=Possible					
I	II	III	IV				
Hazardous Waste Facility Permit	For treatment, storage or disposal of certain wastes, including mud	L	L	R	DHS	N.C.G.S. §130-166.18(c); 10 NCAC 10F	
Tax Certification	For tax reduction for resource recovery, re- cycling, or anti- pollution facilities	P	P	P	DHS	N.C.G.S. §130-166.18(a)(3); 10 NCAC 10C .0500	
Easement over water	For any proposed structures over or in navigable waters	P	P		DOA	N.C.G.S. 146-12; 1 NCAC 6B .0600	
State Environmental Impact Statement	For activities using public monies and affect- ing the environment	P	P	P		N.C.G.S. §113A-4	
Burning Permit	For burning relating to land clearing activities	P	P	P	DFR	N.C.G.S. §113-60.21 to \$60.31; 15 NCAC 9C .0200	
Open Burning Permit	For all open burning unless specifically excepted	P	P	P	DEM	N.C.G.S. §143-215.3; 15 NCAC 2D .0520	
Public Water Supply Certification	If public water supply system must be expanded or constructed			P	DHS	N.C.G.S. §130-166.45; 10 NCAC 10D	
Water Quality Permit	For systems discharging to surface waters	L	L	L	DEM	N.C.G.S. §143-215.1; 15 NCAC 2H .0100	

Table 3-2 (Continued)

Permit	Description	PHASES REQUIRED				Admin- istering Agency	Statutory Regulatory Authority
		R=Required					
		L=Likely					
		P=Possible					
I	II	III	IV				
FEDERAL:							
National Pollution Discharge Elimination System (NPDES)	For point source dis- charges of wastes	L	L	L	L	EPA/ DEM	33 U.S.C. §1342; 40 CFR §125.122+; 15 NCAC 2H.0100
Environmental Impact Statement (EIS)	For any federally li- censed activity sig- nificantly affecting the environment	L	L	L	L		42 U.S.C. §4332; 40 CFR §1+
Prevention of Signi- ficant Deterioration Permit (PSD)	For new sources of air pollution	P	L	L	L	EPA/ DEM	42 U.S.C. §7401+; 40 CFR §52.21 (b)(1)
*\$401 Water Quality Certification	For federally licensed projects with discharges in state waters	R	R	R	L	EPA/ DEM	33 U.S.C. §1341; 15 NCAC 2H .0500
*\$10 Permit	For any work which might impede navigation	R	R	R	P	ACE	33 U.S.C. §401+
*\$404 Permit	For discharge of dredge and fill materials into navigable waters	L	L	L	L	ACE	33 U.S.C. §1344; 40 CFR §235

Table 3-2 (Continued)

Permit	Description	PHASES REQUIRED				Admin- istering Agency	Statutory/ Regulatory Authority
		R=Required					
		L=Likely					
		P=Possible					
I	II	III	IV				
Certification of mobile offshore drilling units	To assure safety of off-shore shore drilling units	L				CG	46 CFR §107
Coast Guard Port Adequacy Certification	To assure adequacy for the transfer of oil or noxious liquid		L		L	CG	
General Permits of Handling Dangerous Cargo	For handling LPG and oil at port if tankers used	P	P	P	P	CG	33 CFR §126.27; 46 CFR §154; 49 CFR §176.27

\*Consolidated under one NRCD Application.

Phases of Activity	Agency Abbreviations
I: Pre-lease	DLR - N.C. Division of Land Resources (NRCD)
II. Exploration	OCM - N.C. Office of Coastal Management (NRCD)
III. Field Development	DOA - N.C. Department of Administration
IV. Production	DEM - N.C. Division of Environmental Management (NRCD)
	DHS - N.C. Division of Health Services (Department of Human Resources)
	DOC - N.C. Department of Commerce
	NRCD - N.C. Department of Natural Resources and Community Development
	DFR - N.C. Division of Forest Resources (NRCD)
	EPA - U.S. Environmental Protection Agency
	ACE - U.S. Army Corps of Engineers
	CG - U.S. Coast Guard

\*Consolidated under one NRCD Application.

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I: Pre-lease	DLR - N.C. Division of Land Resources (NRCD)
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	DHS - N.C. Division of Health Services (Department of Human Resources)
	DOC - N.C. Department of Commerce
	NRCD - N.C. Department of Natural Resources and Community Development
	DFR - N.C. Division of Forest Resources (NRCD)
	EPA - U.S. Environmental Protection Agency
	ACE - U.S. Army Corps of Engineers
	CG - U.S. Coast Guard

## CHAPTER FOUR

### Basic Considerations

#### 4.1 Policy

Any public program, be it for the disposition of public mineral resources or any other purpose, is guided explicitly or implicitly by a set of policies. Which policies for the disposition of public oil and gas resources would best serve the interests of the people of North Carolina is a major focus of this report. In the next three chapters various options are considered, recommendations made, and strategies for their implementation suggested. But even the most basic decisions on the program require some policy guidance, and so before any discussion of a program can begin, a basic policy framework needs to be assembled or formulated.

The number and variety of policy objectives that could be used to shape an oil and gas program are legion. Examples from other state and federal programs and from the literature include:

- receipt of fair market value;
- protection of the natural environment;
- protection of other human uses of state waters and submerged lands;
- protection of the socio-economic system and cultural fabric of the coastal zone from unnecessary disruption;
- control of the rate of development to achieve various purposes, including:
  - maximization of early or overall revenues to the state;
  - maximization of production over the life of the reservoir;
  - rapid development to lessen dependence on foreign sources and to promote economic development;
  - conservation of resources for future generations;
- control of the destination and/or price of hydrocarbons to effect various policy objectives, including:
  - aid to small businesses;
  - aid to N.C. businesses;
  - low prices for N.C. consumers;
- increased competition;
- increased economic efficiency;
- minimal administrative burdens on government and industry;
- avoidance of unnecessary delays in exploration and development;

- maximization of North Carolina business and employment opportunities;
- extensive local government and public participation; and
- balancing of risks and benefits among different regions of the state.<sup>1</sup>

This list is only illustrative and could continue for pages. Some of these policies, such as public participation, can be addressed directly in the design of a leasing program. Others, such as environmental protection or receipt of fair market value, cannot be achieved so directly, and the program instead must seek to create conditions conducive to their realization. A point to be made by the length of this list is that the state basically has a valuable asset (oil and gas exploration and development rights) whose disposition has been authorized by the General Assembly; not only does the decision of whether or how to dispose of those rights involve a number of basic policy decisions, but the opportunity to dispose of them allows the state to pursue a number of policy objectives it may never have had the opportunity to consider previously.

Through various processes the state has already adopted a number of policies relevant to public oil and gas resource disposition, and we should look first to these for guidance. The enabling statute itself provides basic authorization to lease but only vague policy direction:

The State . . . is authorized to grant . . . the right to such mineral deposits, or to sell, lease, or otherwise dispose of same upon such other terms and conditions as may be deemed wise and expedient by the State and to the best interest of the State . . . .

Any sale, lease, or other disposition of such mineral deposits shall be made subject to all rights of navigation and subject to such other terms and conditions as may be imposed by the State.<sup>2</sup>

Similarly, N.C. General Statutes §113-8 charges the Department of Natural Resources and Community Development to "make investigations of the natural resources of the State, and take such measures as it may deem best suited to promote the conservation and development of such resources." Other sources

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<sup>1</sup>See, for instance, U.S. House of Representatives, Conference Report on Outer Continental Shelf Lands Act Amendments of 1978, H. Rept. 95-1474, 95th Cong., 2d sess., p. 92; U.S. Senate, Federal Leasing and Disposal Policies, Hearings Before the Senate Committee on Interior and Insular Affairs, June 19, 1972, pp. 35-37; California State Lands Commission, Report to the Legislature on Proposed Oil and Gas Lease Sale Program, Pt. Conception-Pt. Arguello, Santa Barbara County (n.p., 1981), p. 4; Alaska Stat. §38.05.180(a); Stephen L. McDonald, The Leasing of Federal Lands for Fossil Fuels Production (Baltimore: The Johns Hopkins University Press for Resources for the Future, 1979), p. 2.

<sup>2</sup>N.C. Gen. Stat. §146-8.

are more explicit. Both the North Carolina Constitution<sup>3</sup> and the North Carolina Environmental Policy Act<sup>4</sup> clearly establish a state policy of environmental protection. The Coastal Area Management Act cites several goals for the coastal area management system that could reasonably be applied to any leasing program that will focus on the coastal area. Two of these goals are "to insure that the development or preservation of the land and water resources of the coastal area proceeds in a manner consistent with the capability of the land and water for development, use, or preservation based on ecological considerations," and, "to insure the orderly and balanced use and preservation of our coastal resources on behalf of the people of North Carolina and the nation."<sup>5</sup> The Oil and Gas Conservation Act<sup>6</sup> declares it to be state policy to prevent the waste of oil and natural gas, to protect the rights of owners of an oil or gas reservoir, and to regulate oil and gas activities so as to protect the environment.

As a result of North Carolina's participation in the federal OCS oil and gas program, the state, on the recommendation of the state OCS Task Force, has adopted a number of policies on OCS development that are relevant to, and should be compatible with, any leasing program in state waters. These policies include:<sup>7</sup>

- the OCS program deserves support as a means of reducing the nation's dependence on foreign sources of oil and gas;
- the program should be conducted in an environmentally responsible manner;
- blocks with the highest hydrocarbon potential should be offered first;
- the risks of leasing nearshore blocks should be carefully reviewed in the leasing decision, particularly the risk of an oil spill;
- blocks should not be leased which represent an unacceptable level of risk or strain on significant biological or cultural resources, fisheries, navigation, and other economic activities;
- cultural resources should be protected;
- local governments should be encouraged to participate in OCS planning; and

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<sup>3</sup>North Carolina Constitution, Article XIV, Section 5.

<sup>4</sup>N.C. Gen. Stat. §113A-3.

<sup>5</sup>N.C. Gen. Stat. §113A-102.

<sup>6</sup>N.C. Gen. Stat. §113-382.

<sup>7</sup>Eric Vernon, "Outer Continental Shelf Oil and Gas Leasing: Policies and Issues for North Carolina," mimeo, Office of Marine Affairs, Raleigh, 1983, pp. 13-19.

-environmental studies to fill information gaps should be funded and their results used in management decisions.

The state's "balanced approach" to OCS leasing, which supports leasing of those tracts where oil and gas potential is greatest and restricting leasing where risk is greatest, led the state to object to the inclusion of nearshore blocks in each of the three OCS lease sales held off North Carolina. Given what we currently know about oil and gas potential in North Carolina waters, an extension of these OCS policies inshore would seem to weigh against most state leases at this time, but this is only speculation and a thorough review of the subject will be necessary.

Finally, while the state has no explicit policy requiring receipt of fair market value in the disposition of all state property, it is certainly implicit in many of the regulations adopted by the Department of Administration.

Given these considerations, it is proposed that the best interest of the state will be furthered if any program for the disposition of state oil and gas development rights in submerged lands pursues, at a minimum, the following basic objectives:

- (1) to develop these oil and gas resources in an orderly and timely fashion;
- (2) to provide a fair market return to the state for the disposition of these resources;
- (3) to protect and enhance the natural and human environments;
- (4) to ensure that energy development is pursued within a context of orderly and balanced use and preservation of all coastal resources;
- (5) to minimize administrative burdens on government and industry and maximize the predictability and credibility of the program;
- (6) to enhance competition and economic efficiency; and
- (7) to provide all sectors of government and the public at large with timely access to the decision-making process.

Clearly there are many additional objectives the state could pursue, and a number of these will be mentioned in Chapter Five. Moreover the seven listed here are not necessarily compatible, and there will be times when the state will have to choose which one(s) to emphasize. All seven, we feel, reflect the prevailing philosophy of North Carolina state government, and will be used to provide a framework for the design of an oil and gas leasing program.

One of the fundamental policy decisions the state must confront early in the design of a leasing program is the question of how aggressively the state should promote oil and gas exploration and development. How are "orderly and timely" to be interpreted in the first objective listed above? In the words

of Gen. Stat. §146-8, what is in "the best interest of the State?" On the one hand, the state could approach the matter as another industrial recruitment effort, with the opportunity to provide employment and reduce the state's dependence on imported petroleum. The state instead could take a relatively neutral stance, with no effort to actively encourage development, but with regulations in place to allow development provided that environmental protection and receipt of fair market value are reasonably assured. There are also various gradations between these two positions, but it is beyond the scope of this report to fully explore this question. A first step in this direction might be the preparation of a generic or programmatic Environmental Impact Statement to help determine what is in "the best interest of the State." Based on our research, our interpretation of the charge to us, our discussions with state officials, and our reading of the political climate, the latter or neutral course appeared to us as the one the state is more likely to adopt in the immediate future. For this reason our recommendations, particularly those regarding the leasing process, have been developed along these lines. We recognize, however, that there are also good arguments to be made for taking a more aggressive approach, and have indicated at several places in Chapter Five how the program might be altered to accommodate this approach.

#### 4.2 Government Participation and the Allocation of Leases

##### Government Involvement

Ignoring, momentarily, the limitations of existing statutes, one of the first and most obvious questions to address in considering the development of public oil and gas resources is the extent to which the public sector should be involved. Should the government sell or lease exploration and development rights to private firms and confine its activities to that of lessor and/or regulator, or should it participate actively in the process as a financial partner or even as field operator, through the establishment of a state-owned oil company?

There are many models to choose among from around the world. The standard practice in the United States, at both the state and federal levels, is for the government to lease exploration and development rights to private firms. No active role in financial decisions is sought. There have been suggestions from time to time that the federal government assume responsibility for exploring and even developing the OCS,<sup>8</sup> but such suggestions have not received much support.

Dam describes several forms of government participation practiced elsewhere.<sup>9</sup> These include:

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<sup>8</sup>See, e.g., Office of Technology Assessment, An Analysis of the Feasibility of Separating Exploration From Production of Oil and Gas on the Outer Continental Shelf (Washington, D.C.: Office of Technology Assessment, U.S. Congress, 1975), 290 pp.

<sup>9</sup>Kenneth W. Dam, Oil Resources: Who Gets What How? (Chicago: University of Chicago Press, 1976), 193 pp.

1) Sole government exploration and production. In countries where private oil firms have been nationalized, such as Mexico, the state-owned company may conduct all exploration and development activities itself.

2) Joint venture. Joint venture operating companies may be formed by private oil corporations and the host country (usually represented by the national oil company) to explore and develop licensed territory. These arrangements were popular in the Middle East from the late 1950's through the mid-60's.

3) Service contract. Under this arrangement, an oil company is contracted by the host government to provide specific exploration and development services. At least theoretically, the private firm does not obtain any ownership interest in the natural resources themselves. Iran, Iraq and Venezuela have used service contracts.

4) Production sharing. This arrangement combines elements of the previous two. As used in Indonesia, the private firm serves nominally as a contractor, being given responsibility for exploring and developing petroleum resources within the contract area. Expenses are reimbursable from the oil produced, and the remaining production is shared according to a pre-determined formula between the company and the host country.

While the latter three arrangements may seem distinctly different on the surface, in practice they have usually been written to produce very similar results, including little or no financial risk to the host country and physical control of the product in the hands of the private company.

Advantages of government participation include some control over exploration and production decisions, experience gained from working with private companies, and the symbolism (important in many parts of the world) of not surrendering control of natural resources to foreign corporations. Development solely by a public entity also allows the government to capture both the economic rent accruing from the resource and the normal operating profit of the operator.

There are several compelling reasons for North Carolina not to become actively involved in petroleum exploration and development. The state currently has no expertise and no institution to conduct such a venture. The prospects for success in eastern North Carolina must be regarded as slight, and any public investment in exploration would be very risky. Such participation would also be out-of-step with the free-market, private enterprise philosophy that generally prevails in the state. For these reasons, it is recommended that the state sell or lease public oil and gas rights to the private sector.

#### Sell or Lease?

The statutory authorization for a leasing program (N.C.G.S. §146-8) allows the state "... to sell, lease, or otherwise dispose of any and all mineral deposits belonging to the State. . . ." There are several reasons why oil and gas rights should be leased rather than sold. With leases of

specific duration, the state retains some control over the timing of development, especially to prevent acreage from being held or wells from being shut in for speculative purposes. Furthermore, sale of mineral rights would create a perpetual threat to public uses of the surface. Through the lease document, the state can also retain a fair degree of control over the lessee's conduct. While it might be possible to overcome many of these difficulties through the creative drafting of a deed, it could not be done without the deed appearing more and more like a lease. The public trust doctrine may also preclude the sale of these rights, despite the statute. All other states lease, rather than sell, their mineral rights, and it is recommended that North Carolina do likewise.

#### Allocation Method

If oil and gas rights are to be leased to private firms, the next question is, how are these rights to be allocated? How should the state choose who shall receive leases? Three basic methods have been used in other states and countries to allocate public oil and gas rights:

- 1) first-come, first-served;
- 2) discretionary allocation; and
- 3) competitive bidding.

First-come, first-served. Two general approaches to allocation fall in this category. In one, the first person or corporation to apply for a lease on a particular tract obtains a legal right to that resource, provided certain previously established and often quite minimal criteria are met. No negotiations are involved. The best example of this system is that used for federal onshore lands. Under the Mineral Leasing Act of 1920,<sup>10</sup> federal onshore lands not within any known geological structure of a producing oil and gas field and not otherwise withdrawn from development are available for oil and gas exploration and development on a first-come, first-served basis. Leases are awarded to the first qualified applicant at established terms of 12 1/2% royalty and \$1 per acre or more annual rental. For expiring leases the chaotic situations that resulted when applicants tried to be the first to file after a lease expired led to the implementation of a simultaneous filing system in 1960. Under this arrangement, all applications received within five days of the announcement of a tract's availability are considered to have been filed simultaneously, and the lessee is chosen by drawing. Each applicant may submit only one application. For these leases, then, which account for the majority of lease activity on federal lands, allocation is essentially by lottery.

In the second approach, the first applicant for a lease tract does not acquire any statutory right to the lease, and must negotiate the terms with

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<sup>10</sup>30 U.S.C. §§181-287.

the public authority. Agreement may or may not be reached, but in either case the public agency makes no attempt to identify and negotiate with potential competitors. This approach is followed by Canada in leasing offshore waters that have not been previously leased,<sup>11</sup> and has been the system in use in North Carolina until the present.

Discretionary allocation. Discretionary allocation is the term used by Dam<sup>12</sup> to describe those systems, in common use throughout the world except the United States, where leases or licenses are allocated among applicants according to a set of administratively or politically derived criteria. An excellent example is Britain's allocation of licenses in the North Sea. For each round, applicants have been invited to submit proposals specifying work programs, qualifications of the applicants, blocks desired, etc. Negotiations with applicants regarding their work programs and other aspects of their proposals have been common. Announced criteria used in selecting licenses have tended to be vague; in the first round, for instance, the criteria were announced in the House of Commons by the Conservative minister of power as:

First, the need to encourage the most rapid and thorough exploration and economical exploitation of petroleum resources on the continental shelf. Second, the requirement that the applicant for a license shall be incorporated in the United Kingdom and the profits of the operations shall be taxed here. Thirdly, in cases where the applicant is a foreign-owned concern, how far British oil companies receive equitable treatment in that country. Fourthly, we shall look at the programme of work of the applicant and also at the ability and resources to implement it. Fifthly, we shall look at the contribution the applicant has already made and is making towards the development of resources of our continental shelf and the development of our fuel economy generally.<sup>13</sup>

Criteria were altered and refined in succeeding rounds, the major change being a new criterion that considered the extent of government participation in the venture.

Competitive bidding. The allocation of oil and gas leases by competitive bidding is the method of choice in the United States today. It is used by the Federal government in allocating OCS leases, it is used by all six states (Alaska, California, Texas, Louisiana, Mississippi, and Alabama) with active leasing programs, and it is statutorily required in ten of the sixteen states in which the legislature has specifically provided for the leasing of sub-merged lands.<sup>14</sup> In this approach a leasing proposal, for a certain tract and

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<sup>11</sup>Michael Crommelin, "Offshore Oil and Gas Rights: A Comparative Study," Natural Resources Journal 14:457-500, 1974.

<sup>12</sup>Dam, Oil Resources, p. 4.

<sup>13</sup>*Ibid.*, p. 25.

<sup>14</sup>Alabama (Ala. Code §9-17-65), Alaska (Alaska Stat. §38.05.180f), California (Cal. Public Resources Code §6827), Delaware (Del. Code title 7,

at specified terms, is prepared by the state, and the lease is awarded to the highest qualified bidder in a competition that is open to all interested parties. The bidding variable may be the bonus payment, the royalty fraction, a percentage of net profits, or another variable.

Assessment. Each of these allocation methods has certain advantages and disadvantages. The main benefit of a first-come, first-served approach is that it works efficiently where interest is marginal and sporadic, and where there often is no more than one firm interested in oil exploration. It also shares with discretionary allocation the allowance for negotiation, which provides the public authority with flexibility to construct a lease agreement tailored to the individual capabilities of a firm, and permits the authority to explore and pursue a variety of public objectives.

The main disadvantage of first-come, first-served systems is that they often do not result in the state receiving full market value for the lease. In many cases (as in North Carolina), leases have been awarded for nominal bonus payments. Even where the size of the payment is subject to intense negotiations, the lack of competition for the lease probably results in payments of less than market value. Where preferential status is given to the first applicant, such systems also work to deny other companies equal access to the resources.

The lottery system used for federal onshore lands has been examined in a number of studies which have identified several drawbacks to this approach.<sup>15</sup> Over time the monetary return to the government (consisting of all the \$10 nonrefundable filing fees) appears to have been less than market value, as indicated by competitive state lease sales for comparable land nearby. A dramatic rise in the number of filings in the last few years has resulted in a situation where income from the two methods may now be comparable.) The lottery encourages the involvement of speculators whose sole interest is in reassigning the lease at a profit, thus slowing the development process. In

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\$6128), Florida (Fla. Stat. §253.53), Georgia (Ga. Code §91.106a), Louisiana (La. Rev. Stat. §30:126), New York (N.Y. Envir. Conserv. Law §23-1101), Oregon (Or. Rev. Stat. §274.765), and Texas (Tex. Nat. Res. Code Ann. title 2, sub-chapters 32D and 52B) are required by statute to lease mineral rights competitively. Massachusetts, Mississippi, North Carolina, South Carolina, Virginia, and Washington are not.

<sup>15</sup>Rocky Mountain Mineral Law Foundation, Energy Fuel Mineral Resources of the Public Lands, Vol. III: Legal Study of Federal Competitive and Noncompetitive Oil and Gas Leasing Systems, prepared for the Public Land Law Review Commission (Springfield, Va.: National Technical Information Service, 1970), 726 pp.; General Accounting Office, Opportunity for Benefits Through Increased Use of Competitive Bidding to Award Oil and Gas Leases on Federal Lands, Publication B-118678 (Washington, D.C.: GAO, 17 March 1979), 6 + 59 pp.; General Accounting Office, Onshore Oil and Gas Leasing--Who Wins the Lottery? Publication EMD-79-41 (Washington, D.C.: GAO, 13 April 1979), 18 pp.; General Accounting Office, Impact of Making the Onshore Oil and Gas Leasing System More Competitive, Publication EMD-80-60 (Washington, D.C.: GAO, 14 March 1980), 4 + 59 pp.

some cases leases are obtained by brokers and subdivided into parcels as small as 40 acres for assignment to speculators at a profit, making the reassembling of tracts of sufficient size for exploration and development time consuming and expensive. The system also invites attempts to manipulate it through multiple filings and other means. Finally, though the lottery was instituted as a reform and functions more efficiently and fairly than the system that preceeded it, it also constitutes a form of gambling, with public resources instead of cash awards as the prizes. While some of these problems could be resolved by placing restrictions on who can file and on assignments, such reforms would result in fewer filings and less revenue.

Proponents of the discretionary system typically claim a number of advantages over other approaches, particularly competitive bidding.<sup>16</sup> The ability to negotiate with individual firms has already been mentioned. A second is that, by not requiring large, up-front bonuses, the government does not place a strain on the working capital position of companies, thereby freeing more funds for exploration. In place of bonus payments, the government can extract agreements to pursue more extensive and aggressive exploration programs, leading to faster development of resources with beneficial effects for the economy, balance of payments, and national security. The ability to award leases based on a number of criteria provides the government with the ability to reward admirable traits other than economic efficiency (e.g. contributions to the local economy), to ensure a balanced mix of companies among those awarded leases, and to use the threat of no leases in future rounds to retain an added measure of control over firms.

Champions of competitive bidding claim such advantages are illusory.<sup>17</sup> While the flexibility to negotiate individually over the lease award is lost in competitive bidding, the state may still negotiate collectively with industry over the lease terms before the sale, and may also have to negotiate a myriad of exploration and development details later during the permitting stage. Furthermore, with some skill in drafting the government can write most of the objectives sought through negotiation directly into the lease proposal. If traits other than economic efficiency are to be rewarded, many of these can be written into the lease or into the eligibility criteria for bidding. With regards to the argument that bonus payments weaken companies financially, it is hard to believe that any payments for North Carolina leases will tax the financial strength of large, multi-national oil corporations. Smaller firms may enter the bidding through joint ventures. Moreover, advance payments are not essential to competitive bidding; bidding may be on the royalty or net profits percentage.

The main advantage of competitive bidding is that it establishes an environment in which the government is more apt to obtain fair market value for its leases. Assuming a sufficient number of bidders and no collusion, companies will tend to bid away any above-competitive return from the resource, leaving themselves with a normal operating profit. Since in the long run the most efficient firms will tend to bid highest, such a system will have the additional advantage of enhancing efficiency in the economy. By

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<sup>16</sup>Dam, Oil Resources, Chapter 4.

<sup>17</sup>Ibid.

transferring any above-competitive return to the government, speculators whose chief interest is in assigning their interest at a profit are discouraged.

Dam discusses many of these points in greater detail. However, the major arguments outlined here are sufficient, we think, to support our conclusion that competitive bidding is the preferred method for allocating leases. Under certain circumstances (e.g., when there are few bidders per tract) competitive bidding may not function efficiently, and these situations will be discussed in Chapter Five.

## CHAPTER FIVE

### The Pre-Sale Leasing Program

In this chapter the different elements of an oil and gas leasing program are discussed, from generation of an initial leasing proposal through execution of the lease. In addition, the various considerations as to what to lease and on what terms are explored. The place to begin is with an examination of the oil and gas lease itself and the rights and obligations to which it commits the lessee and lessor.

#### 5.1 The Oil and Gas Lease

Although a public or private landowner has the right to develop his own oil and gas reserves, such ventures are costly and are usually left to specialists. The most common method for delegating development authority to these experts is the oil and gas lease. Under the lease, the developer is given the right to explore and develop the land in exchange for a share in the benefits of such development. The lease itself contains a set of promises and agreements pertaining to the duration of the lease, payment for the lease, the rights and duties of the parties, and the general conduct of the parties in relation to each other and the land. Appendix F reviews these provisions in detail, and a brief account of the more common terms is presented here.

The time period covered by the lease is normally divided into two parts, called the primary and secondary terms. The primary term is an exploratory period of definite duration, usually six months to five years, during which the lessee agrees to undertake exploration activities in an effort to develop producing wells. If production has not begun by the end of the primary term, the lease will terminate, though usually there is a provision extending the lease if continuous drilling operations are underway. The secondary term is of indefinite duration. It goes into effect if production begins by the end of the primary term and stays in effect so long as production continues. Production is usually required to be "in paying quantities," meaning that revenues must exceed operating costs. Should production stop, the lease may usually be maintained by continuous drilling operations, but if in the secondary term there should be no production or drilling for a specified period, the lease automatically terminates.

As compensation for the lessee's right to enter, explore, and drill upon the lessor's land, four types of payment may be made to the lessor. As consideration for the execution of the oil and gas lease, a "bonus payment" is typically made, representing the market value of the lease. The amount of the bonus, which is often made on a per acre basis, may vary widely depending on the demonstrated potential of the area, other terms of the lease, and the potential damage or risk to other resources.

A second form of compensation is the delay rental, which is a fixed amount paid annually during the primary term of the lease until actual drilling is undertaken. Delay rental is considered a payment in exchange for the right to delay the commencement of drilling and development operations on the leased lands, and is usually paid on a per acre basis. Thus, during the primary term, the lessee has a choice of drilling, paying delay rentals, or terminating the lease and avoiding further obligations.

Once production has commenced, royalties -- the third category of payments -- become due. Royalties represent the landowner's share of the revenue in a joint enterprise, with the lessor providing the land and the lessee contributing skill and capital. Ordinarily, royalties are a fractional share of the market value of production, and are paid to the lessor regardless of the costs incurred by the lessee. When the royalties from actual production drop below a specified minimum, the lessee is required to pay a minimum royalty, often equal to the delay rental, which assures a reasonable return to the lessor. Similarly, when a well capable of producing gas in paying quantities has been completed but there is no opportunity to market the gas, a "shut-in royalty" may be required to keep the lease alive during the secondary term.

Finally, a relatively new type of payment known as the profit share may be required instead of or in addition to the royalty. Under this arrangement the lessee pays the lessor a fixed percentage of the net operating profits from the lease, usually after some allowance has been made for recovery of capital expenditures.

The rights and duties of the lessee are similar under all leases. In exchange for payment of the bonus, rentals, royalties, and/or profit share, the lessee is granted the exclusive right to drill for, extract, and produce oil and gas within the leased area, and the nonexclusive rights to explore the area and use the water thereon. The lessor reserves the right to grant rights of way, geological or geophysical exploration permits, or leases for other minerals within the leased acreage to other parties.

The duties of the lessee include the obligation, either express or implied, to develop the land diligently. The lessee is also obligated to drill offset wells to prevent drainage of the reservoir by other parties. Under a pooling clause the lessee is allowed, or may be required at the insistence of the lessor, to pool his lease acreage with that of other lessees to form a more efficient unit that can be drained by a single well. A unitization clause is similar, but involves the combining of much larger acreages under a unit agreement for the efficient development of the entire field or reservoir as a single unit.

Other duties of the lessee include, among other things, obligations to plug abandoned wells, to comply with all state and federal laws and regulations, to keep accurate records, and to indemnify the lessor against specified types of claims. Furthermore, under most leases the lessee retains the right to reinject natural gas to repressure the formation without paying royalties on the gas, to drill directional wells into the leased area from other lands, to suspend operations under certain circumstances, and to surrender all or part of the lease at any time. In addition to the lessee's

rights and duties, the lessor (if a public agency) retains the right to issue rules regarding well spacing, casing, and plugging, and to inspect the operations and records of the lessee. Additional provisions of the lease commonly govern the administration of the parties' relationship under the lease, and deal with such things as cancellation and default, settlement of ambiguities in the lease, and arbitration of disputes.

## 5.2 The Leasing Process

### Introduction

The process leading up to the competitive sale of public oil and gas leases can be divided into four basic steps:

- 1) An initial leasing proposal is generated based on indications of industry interest and input from other sources.
- 2) The proposal is reviewed. Information on the area is gathered, and comments may be sought from state and federal agencies, local governments, industry, and the public.
- 3) Based on these comments and information, the state decides what to lease and on what terms.
- 4) The lease sale is held and leases are executed with the high bidders.

The details and timing of these steps can be organized in a number of different ways, as can the timing of individual sales within a leasing program. The federal government and the states provide several different models. Tables 5-1 and 5-2 present background information on each of the active leasing programs and their approaches to sale scheduling, and Figure 5-1 illustrates how each of the programs typically organizes the events leading up to an individual sale. Various details of these programs will be examined throughout this chapter, but it is worth noting now the diversity among programs. Such diversity may be traced to differences among the states in oil and gas leasing and production history, in the economic importance of the oil and gas industry, and in the general level of public environmental awareness or concern.

### Starting Assumptions and Considerations

There are three points that should be made at the outset of this discussion of a leasing process for North Carolina. First, the reader should understand that the leasing process proposed in this subchapter is based on two important considerations: our assumption that the state does not want to actively encourage oil and gas exploration at this time, but prefers to take a neutral stance, and that prospects for oil and gas in North Carolina appear meager and industry interest is currently low. Should either of these conditions change, procedures other than the ones recommended here may be appropriate or necessary.

Table 5-1

## United States Offshore Drilling and Production Data

<u>State Waters</u>	<u>Total Offshore Wells*</u> <u>Drilled to Jan. 1, 1980</u>	<u>Accumulated Offshore</u> <u>Production to</u> <u>Jan. 1, 1981</u>	
		<u>Oil</u> <u>(million bbls)</u>	<u>Gas</u> <u>(billion ft<sup>3</sup>)</u>
Alaska	361	734.6	833.2
California	3,305	1,757.9	649.1
Florida	15	0	0
Louisiana	3,769	1,217.9	9,355.7
Texas	929	22.3	2,269.3
Washington	2	0	0
<u>Federal Waters</u>			
Alaska	19	0	0
Pacific	418	195.3	80.2
Gulf of Mexico	16,427	5,230.1	48,451.4
Atlantic	21	0	0

\*Offshore wells are defined as those located beyond natural shorelines; wells drilled in sounds, bays, and river mouths are not included.

Source: American Petroleum Institute, Basic Petroleum Data Book, Petroleum Industry Statistics, Vol. 2, No. 2 (Washington, D.C.: API, 1982), Section XI, tables 8, 9.

Table 5-2

## History and Sale Scheduling of Selected Offshore Leasing Programs

<u>Program</u>	<u>Offshore Leasing History</u>	<u>Sale Scheduling</u>
U.S.	Over 60 competitive lease sales held since 1954 under Outer Continental Shelf Lands Act; first sale in each region was: 1954 (Gulf); 1963 (Pacific); 1976 (Alaska and Atlantic)	4-9 sales per year, based on 5-year leasing schedule, updated periodically; intervals between sales irregular
Alaska	Except for a five year hiatus in the late 1970's, competitive sales have been held regularly since 1959; 28 offshore sales through 1982	1-2 offshore sales per year based on 5-year leasing schedule, updated annually; intervals between sales irregular
California	Long history of competitive offshore sales. Leasing halted after 1969 Santa Barbara spill; first sale since then was scheduled for Aug. 1983, but postponed by litigation	Sales scheduled irregularly, based on environmental and drainage concerns and industry interest; in addition to postponed sale, sale of quit-claimed tracts in Santa Barbara channel planned.
Louisiana	Long history of competitive offshore sales	Sales held second Wednesday of every month
Texas	Long history of competitive offshore sales	Sales of Gulf lands held twice each year, in April and October
Alabama	Competitive sale upon request until major find in 1979, now OCS process used; 1981 sale resulted in \$449 million in bonuses for 13 tracts leased; smaller sale held in 1982	Sales scheduled irregularly depending on industry interest, development on existing leases, and other factors; currently one sale scheduled in 1984
Mississippi	Negotiated leases upon request until 1980, now using OCS process; lease sale No. 1 (1982) resulted in \$3.2 million in bonuses for 2 tracts leased	Sales scheduled irregularly, depending on industry interest and other factors; no further sales currently scheduled

[illegible]

Code: C: Call for nominations/comments/information  
D: Nominations/comments/information due  
DED: Draft environmental document released  
PH: Public hearing or meeting  
PED: Final environmental document released  
P: Proposed notice of sale or notice of intent to lease  
F: Final notice/advertisement of sale  
S: Sale

**Note:** Most milestones vary slightly in name and content among programs but have been labelled the same for ease of comparison; it should be kept in mind that these milestones are not exactly equivalent among programs. The environmental document, for instance, is called an Environmental Impact Statement in the federal program, a Social, Economic, and Environmental Analysis in Alaska, and a Program Environmental Impact Report in California, and the purpose and contents of each are different. Some of these distinctions among programs are discussed in the text.

<sup>1</sup>California has gone through pre-sale preparation only once in the last 15 years, and this schedule illustrates the actual sequence of events leading up to the Point Conception/Point Arguello sale that was scheduled for August 1983. Although the sale has been postponed indefinitely by litigation, it is shown as if it had taken place when scheduled.

2This schedule depicts the actual sequence of events leading up to Mississippi's single offshore sale, in July 1982. The sale was originally scheduled for May, and regulations anticipate that the Notice of Intent to Advertise and the Invitation for Bids will be issued in the consecutive months preceding the sale. In this case, the sale was postponed two months after the Notice of Intent was released while major changes were made in the sale area.

Second, the use of competitive bidding to select the lessee places several important constraints on the leasing process employed by the state. Among these are:

- 1) The information required from prospective bidders to participate in the auction must be comparable in preparation costs, so as not to place any bidder at a disadvantage. The amount of information required should preferably be as small as possible, so as to minimize the costs of participation.
- 2) Information submitted by prospective bidders may be used to qualify bidders to participate, but may not be used to select the lessees; selection should be based solely on monetary bids.

These two constraints have several ramifications. The most important is that the firm proposing a tract for leasing should not be required to submit an environmental impact statement or proposed development plans, unless all prospective bidders are required to do so. But the latter would result in duplication and waste, and would significantly increase the costs of participation, resulting in fewer bidders. Moreover, these documents would not be used to select a lessee, but at most only to qualify bidders, assuming equitable criteria could even be established. Instead, any environmental review document prepared before a lease sale should be the responsibility of the state. Oil and gas technology is sufficiently standardized that the state can predict, fairly accurately, the technology that will be used and the types of impacts that will result, irrespective of the particular lessee. The state may require that the costs of the document be borne by the winning bidder, but it should not require a bidder before the sale to prepare such a document.

Furthermore, since the lease will be awarded before the development plans for the lessee are known, it behooves the state to make a serious attempt to anticipate the possible impacts of such development, and to address those that are not covered under existing laws through lease terms and stipulations. Several of these issues will be expanded upon later in this chapter.

Finally, the recent experience of state government in reviewing lease proposals is instructive in suggesting how a leasing process should be designed. The most recent application for an oil and gas lease of submerged lands was received in June of 1980 from Mr. Shirley Murphy. The request was for a lease on two tracts of submerged lands totalling approximately 35,160 acres in the headwaters of the Alligator River and near Stumpy Point in Pamlico Sound, and an 18-month option to lease approximately two million additional acres of submerged lands north of Beaufort. A chronology of the review of this proposal is given in Table 5-3. During the course of this review a number of comments on procedural matters were received from state agencies; these comments indicated, among other things, a need or preference in the future for:

- more information on the proposed development;
- more information on the applicant;
- opportunity for meaningful review by state agencies, local governments, and the public;

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Table 5-3

Chronology of Major Events in the Review of the Murphy Lease Proposal

<u>Date</u>	<u>Event</u>
June, 1980	Lease application received
June-Dec., 1980	Application reviewed and approved by Division of Land Resources, Earth Resources Council, NRCD Secretary, Dept. of Administration, and Attorney General's Office, as required by 15 NCAC 5E.
Dec. 9, 1980	Lease submitted to Governor and Council of State (COS) for approval; COS decides more information needed, appoints subcommittee to study proposal and make recommendations at January meeting.
Jan. 6, 1981	COS directs NRCD to solicit public comment on proposal
Jan.-Feb., 1981	Letters sent to chairmen of county commissioners in project area, and notices published in several newspapers; minimal response
March 3, 1981	COS approves lease subject to Attorney General's Office's approval
July 23, 1981	COS rescinds approval due to inadequate review and inconsistencies with state OCS policies; directs NRCD to continue investigating request with respect to environmental protection and resource potential
late July, 1981	NRCD Asst. Sec. directs staff to (a) resolve Murphy lease question, and (b) develop long-range procedures for reviewing lease proposals
Sept. 5, 1981	Murphy lease proposal submitted to state clearinghouse for distribution and review
Oct., 1981	Clearinghouse and consistency reviews completed; many negative comments, proposal deferred indefinitely

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- a full environmental analysis of the proposal;
- coordination to ensure that all potentially harmful impacts are regulated either through lease terms or post-lease permitting;
- review and revision (as needed) of all existing regulations governing oil and gas development, before the lease is executed;
- policy review to ensure that lease issuance is consistent with other state policies, particularly those dealing with OCS issues.

#### A Proposed Leasing Process

The remainder of this subchapter is devoted to a discussion of how North Carolina might organize the process by which submerged lands are considered for leasing. The first three of the four basic steps described at the beginning of the subchapter are dealt with here; the organization and conduct of the sale itself is discussed in section 5.6.

Generation of the Proposal. The initial leasing proposal -- that such-and-such an area be offered for lease -- can be generated in several different ways, and the experiences of the OCS and various state programs are instructive.<sup>1</sup> All rely to a large extent on expressions of industry interest, as it is obviously wasted effort to offer leases for which there is no market.

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<sup>1</sup>Louisiana and Texas rely almost exclusively on applications from industry to decide what areas will be offered for lease. Nominations are accepted at periodic intervals. Few applications are rejected, and only rarely are unnominated tracts offered for lease.

Some states with small or nonexistent leasing programs, such as Georgia and Virginia, also rely exclusively on applications from industry. Interest in these states is so low that no dates for receipt of applications are set, and each application is handled as it arrives.

The other major leasing states -- Alaska, California, Alabama, and Mississippi -- make use of other considerations and sources of information in generating proposals. Typically they rely on industry and their own staffs to determine when to schedule a sale in a particular area. Formal, confidential nominations from industry are then solicited, and the states use these nominations together with their own geological and environmental information and in some cases public comment to identify a proposed sale area. These programs use far more flexibility in rejecting some nominations and adding unnominated tracts to assemble proposed sale areas that reflect state objectives. The U.S. once used a similar approach for its OCS program, but with the new area-wide lease sale concept it has moved a step closer to the Louisiana/Texas approach of offering almost any tracts in which industry is interested.

Each of these approaches is suited for a different set of conditions, depending on the history of oil and gas production in a state, the amount of interest in offshore tracts, the size and diversity of the offshore area, and the number and types of factors the state wishes to consider in making a leasing decision.

Given the present lack of interest in North Carolina's submerged lands and the rarity with which applications have been received (roughly once every 2-4 years), a continuation of the former practice of taking no action until unsolicited applications are received from industry is recommended. (Of course, formerly the application was an application to lease, while now it would be an application to offer for lease.) The advantages of this approach are that (1) no state effort is spent on soliciting industry interest and preparing a sale schedule where interest doesn't exist; and (2) where there is interest, this approach accomodates it quickly and responsively by focussing immediate attention directly on requested tracts.

What information should be submitted with the application? The area for which a lease is sought should be specified, of course. Beyond this, the applicant should be required to submit only information required of other bidders, since to do otherwise would put the applicant at a competitive disadvantage, as discussed above. Documentation needed to qualify the applicant as a bidder should be included, since there is no reason to accept a nomination from someone ineligible to bid. The applicant should not be requested, though, to provide proposed development plans or an EIS. These are the responsibility of the state, though their cost may later be charged to the successful bidder.

Rather than require the state to begin the extensive review process for every application, whenever received, and only for nominated tracts, there are a couple ways to build flexibility and greater efficiency into the system. First, when the state perceives an interest in submerged lands leasing (through inquiries to the state, applications for exploration permits, requests to review well cores, etc.), the state should be authorized to issue a "Request for Applications," setting a single date during the following 1-2 years when applications will be accepted, thereby allowing applications that might trickle in over time to be considered all at once. Second, the state should be allowed to include additional unnominated areas in the proposal for consideration. All of the seven programs examined have this latter authority, and the North Carolina program should possess it as well.

Since review of leasing proposals will involve a great deal of time and effort on the part of the state and other groups, there should be some means to discourage applications for tracts which the companies have no serious interests in, but which are used to obscure from competitors the real objects of their interests. Several states have adopted filing deposits or fees for this purpose. Alabama requires that a \$25 nonrefundable filing fee accompany every nomination. Applications in Louisiana must include a \$300 deposit, which is returned if the tract is not offered or if the applicant bids on the tract, regardless of whether the bid is accepted. Texas is considering a similar measure. It is recommended that North Carolina do the same, i.e., that the state require every application to be accompanied by a filing fee of \$X (\$300-500?) per block, which will be returned if the block is either (a) not offered, or (b) offered and the applicant bids on it, regardless of whether the bid is accepted. Otherwise, the deposit will be forfeited.

Finally, the identity of the applicant should be kept confidential. Confidentiality is important in preserving competitive equality and in

providing less opportunity for collusion. Only Louisiana of the seven programs examined publicly identifies the applicant or nominator.<sup>2</sup>

Review of the Proposal. It is suggested that the objectives of the review process be:

- to establish avenues for incorporating all relevant information into the decision-making process;
- to provide for the involvement of all state and federal agencies with responsibilities related to oil and gas exploration and development;
- to provide for the involvement of local governments and all interested segments of the public, including the oil and gas industry, other affected industries (e.g., fishing and tourism), environmental groups, and concerned citizens;
- to identify before the lease is executed the major permit restrictions that will be imposed later; and
- to accomplish the review within a reasonable time, and with a minimum of paperwork and other administrative burdens.

To meet these objectives, the following review process is proposed:

(1) Pre-application contacts. These are important for advising the potential lessee of the leasing process, the permits required for exploration and development, the geologic information already available from previous exploration, and other matters. There is a need throughout the leasing process for one office to serve in a coordinating role, and this should be the office to provide informal, pre-application consultations as well. It is natural that the Division of Land Resources (DLR) provide both these services, by reason of expertise and because it already serves in this capacity.

(2) Application and preliminary review. After an application is received, several important questions can be answered relatively quickly (within 2-3 weeks) which will determine whether the proposal merits further, substantive review. These questions are:

(a) Is the application complete? Is the form filled out properly, is the deposit attached, and has the applicant established his eligibility as a bidder? These steps are relatively mechanical and can be easily handled by Land Resources.

(b) Does the state in fact own the mineral rights in the nominated area, and can they be leased? The question of existing property rights in the

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<sup>2</sup>This will require a statutory exception to Chapter 132 of the General Statutes, which defines virtually all state-held documents and information as "public records" and requires that they be available for examination by the public. See note 103, below.

state's submerged lands is currently being addressed by a task force of representatives from Natural Resources and Community Development, Administration, and Justice (see Section 5.4). One of these agencies (State Property Office?) would be in the best position to answer this question.

(c) What is the condition of the market for offshore leases? Is this a good or bad time for the state to be selling? The market for offshore leases shows cyclical patterns, and an understanding of these changes can make a big difference in state revenues. Again, Land Resources will probably be in the best position to judge this, with help from economists elsewhere in the Department (Planning and Assessment?). The Secretary should make the final decision on whether or not to defer an application because of market conditions.

(d) Would issuance of a lease clearly contravene a standing policy of the Department? Such policies will be discussed further in Section 5.3; an example of such a policy might be a ban on oil and gas leasing in the sounds north of Cape Lookout. Assuming the policies are easy to interpret, this is a fairly mechanical task and can be easily handled by Land Resources.

The procedure, then, is that upon receipt an application is referred to Land Resources. That division checks the application for completeness and for any clear contravention of Department policy. The State Property Office is consulted on the availability of the oil and gas rights for lease, and others are consulted on the condition of the market for offshore leases. If none of the answers to these questions indicate the application should be rejected or deferred, or if the only reason for deferral is the condition of the market, Land Resources forwards its findings to the Secretary for his concurrence. Upon the Secretary's agreement that the application meets the above tests, the application enters the next, or substantive, stage of review.

(3a) Statutory considerations for substantive review. In designing a substantive review process for leasing proposals, the first step is to determine and evaluate what relevant statutory or administrative requirements for review already exist. There are five sets of requirements to consider, excluding the old regulations for submerged lands leasing (15 NCAC 5E) which the recommendations of this report are intended to replace. These are:

(a) Under the leasing statute itself (G.S. §146-8), the Secretary of NRCD may advise the state to execute a mineral lease, with appropriate terms and conditions, when he feels such a lease would be in the state's best interests. Any sale, lease, or contract must be approved by the Department of Administration and by the Governor and Council of State.

(b) The North Carolina Environmental Policy Act<sup>3</sup> (SEPA) requires that, "Any State agency shall include in every recommendation or report on proposals for legislation and actions involving expenditure of public moneys for projects and programs significantly affecting the quality of the environment of this State, a detailed statement by the responsible official setting forth the following. . . ." State rules for SEPA were promulgated by the

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<sup>3</sup>N.C. Gen. Stat. §113A-1 to §113A-10.

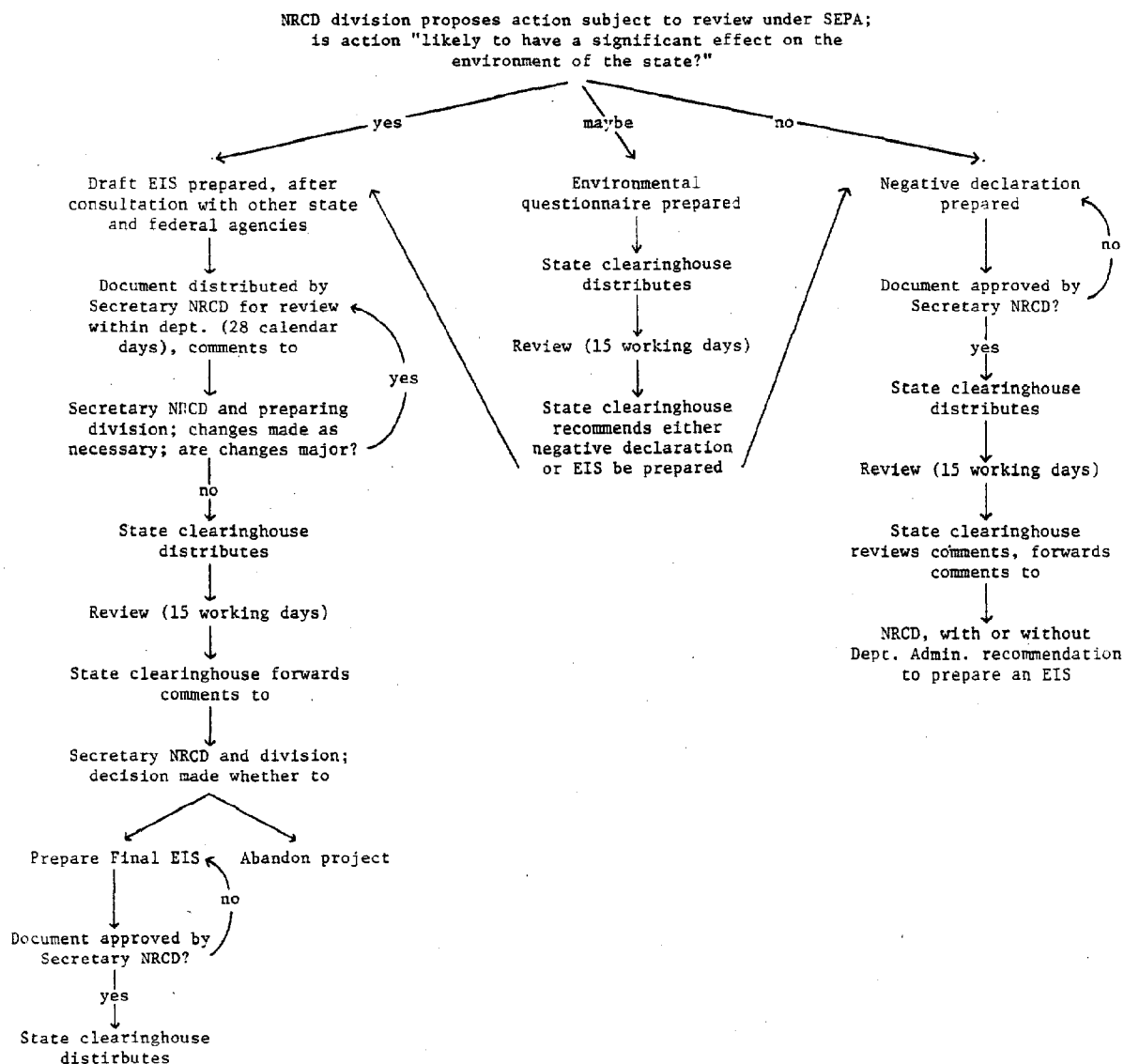
Department of Administration at 1 NCAC 25, and Departmental rules by NRCD at 15 NCAC 1D; the procedural requirements of these rules for NRCD actions are shown in Figure 5-2. Unfortunately these rules lack clarity, and their implementation has not been uniform. The state has been reviewing its implementation of SEPA for some time, and an executive order from the Governor clarifying responsibilities and initiating rule revision is expected soon. Once it is issued, the Department of Administration will begin revising its SEPA rules governing statewide implementation of the act, and other departments will follow suit.

At this time it is difficult to predict how SEPA will apply to submerged lands leasing under the new rules. Currently there are two major questions that the rules will hopefully answer. First, as interpreted in court cases and opinions of the Attorney General, three conditions are needed to trigger a SEPA-required EIS: (1) There must be a state action, (2) public moneys must be involved, and (3) the action must have a significant impact on the state's environment. The leasing of state-owned submerged lands is clearly a state action, and in most cases we expect that there would be a determination of significant impact. The question is: Are public moneys involved? Funds spent on administration of an ongoing program do not qualify, so it is a question of whether public oil and gas resources are considered "public moneys." The existing rules are not clear on this subject. Secondly, if an EIS is required, which agency is responsible for preparing it -- NRCD, Administration, or the Council of State? Since the Council of State makes the final decision on whether or not to lease, a good argument can be made that it is their action, and not NRCD's request under §146-8, that triggers SEPA. The Council of State, however, has never prepared an EIS or even considered which of its actions fall under SEPA.

Even if SEPA is found not to be applicable, a strong case can be made for using an EIS-like process anyway. The decision whether or not to permit the oil and gas leasing of state-owned submerged lands will be one of the most important natural resources decisions any administration will make. It is one that the Council of State and various state agencies have emphasized should have the benefit of state agency, local government, and public input. Moreover, with respect to the OCS program the state has consistently supported a process that encourages open and knowledgeable discussion of the risks and benefits of oil and gas development and that allows meaningful input from states, local governments, and the public. Such goals can best be achieved by producing an EIS and giving it wide exposure for comment. Authorization for preparing an EIS-like document would seem to be implicit in the requirement of G.S. §146-8 that leasing be on such "terms and conditions as may be . . . to the best interest of the State." Procedures for preparing such a document could be written into the leasing rules.

(c) Executive Order No. 15 of Governor Hunt requires, among other things, that the use and disposition of state-owned lands be consistent to the maximum extent possible with the coastal management program, including state guidelines and local land use plans. Consistency determinations are made by the Office of Coastal Management (OCM). For projects that require an EIS or negative declaration, standard procedure is for OCM first to examine the comments generated by the clearinghouse review, then discuss any difficulties OCM has on the project with the sponsoring agency, and then find that the

Figure 5-2. Principal Review Procedures for NRCD Actions Subject to the North Carolina Environmental Policy Act



Source: 1 NCAC 25 and 15 NCAC 1D; procedures for appeal of agency decisions (1 NCAC 25 .0106) are not illustrated.

proposal is either consistent, consistent with conditions, or not consistent with the coastal management program.

(d) N.C. Gen. Stat. §143-341(4)(f) reserves a major role for the Department of Administration in any lease transaction. This provision gives Administration, with approval of the Governor and Council of State, the power and duty to make all leases of state lands, although the Governor and Council may exempt certain classes of transactions from this requirement. However, NRCDC currently cannot seek exemption since the leasing statute itself, G.S. §146-8, specifically requires Department of Administration approval. While it is apparent in §146-8 that NRCDC is intended to have major review responsibilities, Administration also has a statutory duty to review and approve any lease proposal. What is needed, then, is a means for coordinating or combining these reviews to prevent duplication and to reach decisions satisfactory to both departments.

(e) Several public agencies independent of the Governor have the ability to deny necessary permits to oil and gas lessees or in other ways to prohibit development. These include several federal agencies (particularly the Army Corps of Engineers), the Environmental Management Commission, the Coastal Resources Commission, and the county or counties in which the lease blocks occur. There is a possibility that the state, having decided that leasing would be in its best interests, could lease an area only to be frustrated in its attempts to develop it through permit denials to the lessee. Short of statutory change, the authority of these bodies to prohibit oil and gas development cannot be removed. It behooves the state, therefore, to provide these bodies with every opportunity for review of the leasing proposal and to work with them to fashion a proposal acceptable to all parties.

The role of the Environmental Management Commission stems from its authority to issue or review water (and possibly air) quality permits needed by offshore oil and gas operations. The standards for these permits are fairly specific, though, and most bidders should be able to estimate whether such permits can be obtained and the costs of compliance with permit conditions. The same is not true of the CAMA major permit (and to a lesser extent, the dredge and fill permit) that must be obtained from the Coastal Resources Commission (CRC). CAMA permit standards listed in Gen. Stat. §113A-120 are rather vague, with much room for interpretation, particularly regarding an activity such as oil and gas exploration for which no precedents under CAMA and no specific use standards exist. What is needed and recommended to give credence and predictability to the leasing process is for NRCDC (a) to ask the CRC to examine the question of submerged lands oil and gas development and to prepare state guidelines under which such development would be permissible, and (b) to consult the CRC during normal pre-sale reviews and make a special effort to allay its objections and concerns.

During the 1983 session, the General Assembly passed HB 865,<sup>4</sup> which amends the grant of zoning authority to counties in G.S. §143-340 by extending it to include the estuarine waters within the counties' boundaries. All inshore waters (those landward of the barrier islands) are affected, but not those in the three-mile contiguous zone seaward of the islands. The effects of the

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<sup>4</sup>1983 N.C. Session Laws, Ch. 441.

amendment must be read in conjunction with CAMA. The amendment enables a county to impose limitations on submerged lands oil and gas development by means of a zoning ordinance. Such an ordinance would require the county's land use plan to be amended to include such limitations, as Gen. Stat. §113A-111 requires that local ordinances and the land use plan be consistent with each other within areas of environmental concern. Since local land use plans are incorporated into the state's coastal management program and compliance with them is required before a permit can be issued under G.S. §113A-120, such a limitation would have the effect of requiring the CRC to deny any CAMA permit for oil and gas development within that county's estuarine boundaries as well.

Since a county can amend its land use plan on 90 days notice, there is the potential that a county could frustrate the purpose of a sale long after the sale is held and well into the lessee's planning activities. There are three ways in which such difficulties can be avoided. First, the statutory grant of authority to counties could be amended to exclude a class of actions including oil and gas development in estuarine waters. Second, since CAMA requires that local ordinances covering areas of environmental concern be consistent with local land use plans and that the latter be consistent with state guidelines adopted by the CRC, then if the CRC adopted guidelines setting specific conditions under which oil and gas development would be approved, any limitations under county zoning authority would necessarily not be in conflict with the state guidelines. Finally, the county or counties affected could be closely involved in pre-sale planning, in the hopes that, if all their objections could be met in the design of the lease sale, they would not subsequently prohibit development through a zoning ordinance. The latter course should be followed in any case, but since it has substantial risk it is recommended that the second option also be pursued.

All of the statutes discussed above have requirements or suggest procedures for substantive review that are compatible with the objectives of the review process discussed earlier and that to a large extent fulfill them. Assuming the uncertainties regarding SEPA are resolved in favor of its application to submerged lands leasing, it is recommended that these existing procedures be followed, with a few minor alterations, rather than new procedures be designed specifically for this program.

(3b) Procedures for Substantive review. A major preliminary step in establishing a review process is to determine who shall be responsible for conducting the review. One office or group is needed to coordinate the review, to prepare or at least oversee preparation of the environmental document, to review comments, and to make recommendations to the Secretary. It would also be useful if this office or group included people knowledgeable on permit requirements and conditions who could coordinate permit review and lease administration after issuance of the lease. Options include: (1) the Division of Land Resources with advice as needed from other NRC divisions and state agencies, (2) the OCS Task Force, and (3) a specially designated task force or working group of NRC and other agency personnel, chaired by Land Resources. (The Earth Resources Council constituted a fourth option until it

was abolished by the General Assembly in July of 1983.<sup>5)</sup> Of these, the first option is not recommended. Expertise will be required in many different environmental fields, and a great deal of discussion and coordination will be needed to ensure that the full array of potential environmental problems have been satisfactorily addressed. Recommendations to the Secretary on such a complex issue would better be generated by consensus among the agencies most involved, rather than by a single division such as Land Resources.

The latter two options both have much to recommend them. The OCS Task Force is an interdepartmental group with a proven track record and a substantial amount of expertise in offshore oil and gas development. It includes representatives of a number of different state agencies, as well as representatives of local governments, and is chaired and staffed by the Office of Marine Affairs in the Department of Administration.<sup>6</sup> This arrangement facilitates use of the Task Force as an open, neutral forum for discussion between development and conservation minded interests. Advice would be generated not only for the Secretary of NRCD, but also for Administration and other state agencies and for the Governor and Council of State. A more narrowly defined and specially constituted task force within NRCD, on the other hand, would arguably be more responsive to the Secretary of NRCD and his statutory responsibilities. It could be constituted to reflect the specific interests involved in any single sale, and could include some of the representatives currently on the OCS Task Force (thus drawing on their expertise), as well as representatives of agencies not currently on the Task Force but with major interests in submerged lands leasing, such as Wildlife Resources and the State Property Office. No recommendation is offered on which of these two options should be chosen.

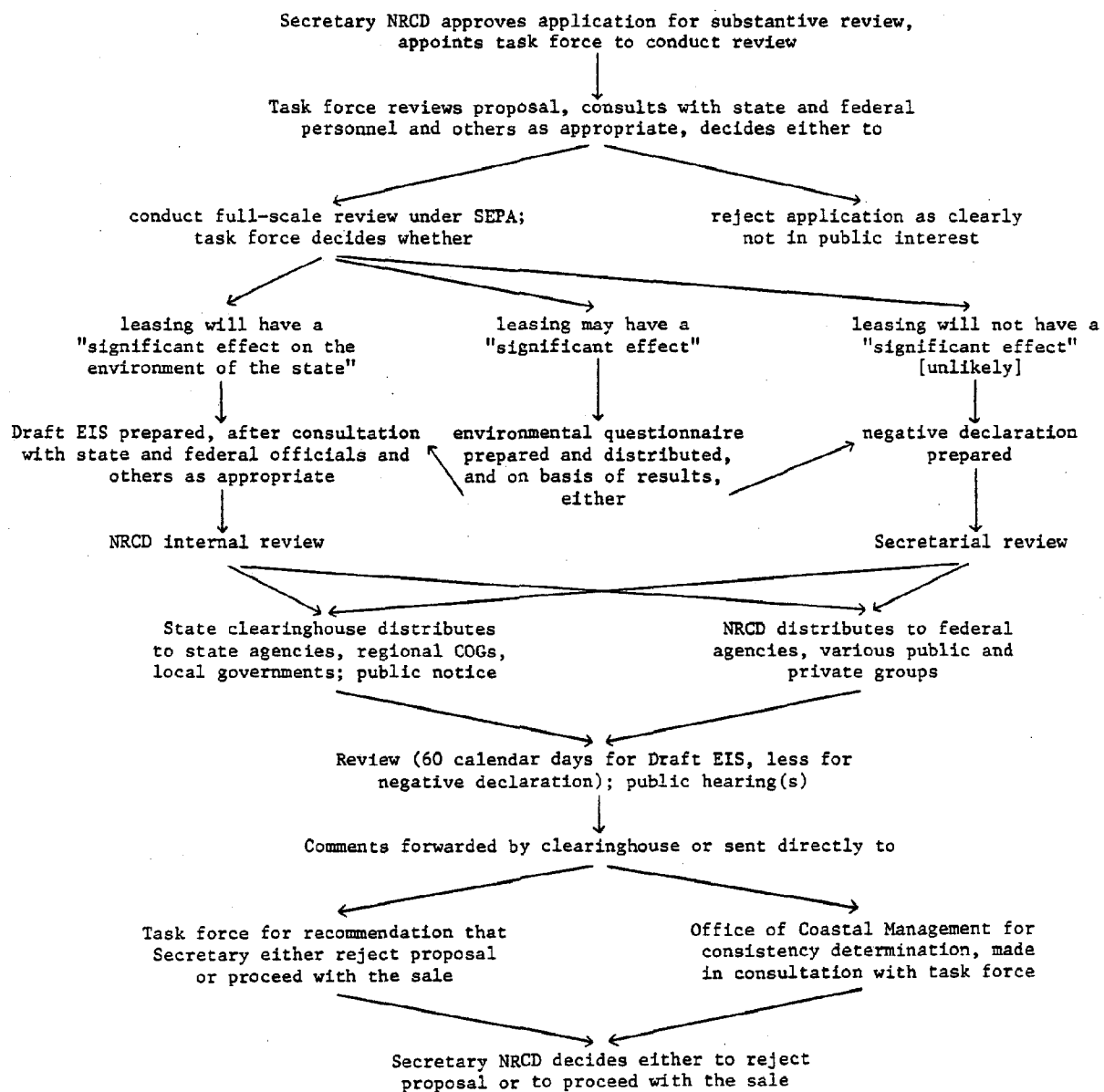
Due to uncertainties regarding future implementation of SEPA and regarding who will coordinate review of leasing proposals, we cannot recommend a specific procedure for substantive review at this time for incorporation into administrative rules. To illustrate what such a process might look like, however, we have, for the sake of argument, developed a review process based on existing SEPA rules, assuming SEPA is applicable and that NRCD is the sponsoring agency, and that a working group would be appointed by the Secretary of NRCD to coordinate review. Given these assumptions, the following procedures for substantive review are recommended (Figure 5-3; keep in mind that any change in assumptions will require appropriate modifications in these procedures):

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<sup>5</sup>1983 N.C. Session Laws, Ch. 667.

<sup>6</sup>The OCS Task Force is chaired by the OCS Coordinator in the Office of Marine Affairs and includes representatives of the Division of Land Resources (NRCD), Office of Coastal Management (NRCD), Natural Resources Planning and Assessment (NRCD), Division of Environmental Management (NRCD), Division of Marine Fisheries (NRCD), State Ports Authority (Commerce), Office of Industrial Development (Commerce), Energy Division (Commerce), Underwater Archaeology Unit (Cultural Affairs), Department of Transportation, Association of County Commissioners, and N.C. League of Municipalities.

Figure 5-3. Proposed Substantive Review Procedures for Submerged Lands Oil and Gas Lease Applications.



The Secretary, upon approval of an application for substantive review, appoints a working group and refers the application to it. This group meets and, in accordance with Departmental SEPA rules, consults informally with other state and federal personnel and may consult with local governments, industry, environmental groups, and others as appropriate. Scoping meetings may be held. The result will be one of two decisions:

(a) Recommendation to the Secretary that the application be rejected, on the grounds that granting of the lease would clearly be not in the public interest, or that development of the lease would result in an unavoidable statutory violation.

(b) Determination that the application merits further review, based on the decision either that the lease would be clearly in the public interest, or that it is unclear what the public interest requires. In this latter case, since the issue is so complex and the statutory criterion of "public interest" so vague, it is advisable to enter the EIS process and allow a full review so that all sides of the issue can be fully aired, even though the task force has not yet elected to support the proposal. The task force must then decide among three further alternatives:

(b1) Leasing will not have a "significant effect on the environment of the state." A negative declaration is prepared and recommended to the Secretary. To permit a meaningful review, the declaration should contain, at a minimum, a description of the area to be leased, proposed lease terms and stipulations, a brief description of possible oil and gas activities under the lease (with references to more detailed information), a summary of environmental considerations, and a description of permits and regulations that will apply to lease activities.<sup>7</sup> If the Secretary concurs with the negative declaration, it is then sent to the state clearinghouse for distribution and review in accordance with 1 NCAC 25 .0206. However, it is difficult to believe that a negative declaration could be issued for any leasing proposal in the foreseeable future, and negative declarations will not be discussed further here. The procedures for their review are considered adequate, though with the same reservations that apply to EIS review procedures, discussed below.

(b2) Leasing may have a significant effect. In this case an environmental questionnaire is distributed pursuant to 1 NCAC 25 .0203. Upon its completion, the working group must decide between (b1) and (b3).

(b3) Leasing will have a "significant effect on the environment of the state." An environmental impact statement is then prepared, with proposed lease terms and stipulations, and sent to the Secretary as required by departmental rules. The draft EIS is circulated within the Department for at least 28 days, comments are reviewed, changes made as necessary, and the draft statement, with Secretarial approval, is submitted to the state clearinghouse.

State regulations give preparing agencies the authority to charge the project or sponsoring agency the cost of EIS preparation.<sup>8</sup> These costs should

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<sup>7</sup>See 1 NCAC 25 .0202 for other requirements.

<sup>8</sup>1 NCAC 25 .0205.

not be charged to the applicant, but could be charged to the successful bidders; this was to be done in the Point Conception sale in California. Such action really has only public relations value, as the amount charged only lowers each bid by an equal amount.

In reviews of the Murphy lease, a common complaint was that the proposal did not provide sufficient detail about proposed exploration and development activities. With competitive bidding, this lack of detail will be common. The EIS authors can offer likely development scenarios, but reviewers will not have specific plans on which to comment, and should be prepared for this difference between a lease sale proposal and most development proposals they review.<sup>9</sup> Opportunities for review of detailed plans will come at the permitting stage.

Currently, standard procedure is that upon submission of an EIS to the state clearinghouse, copies are distributed to appropriate state agencies and affected regional councils of government, who forward copies on to local governments in the project area. Notice of the document's availability is also printed in the Environmental Bulletin. Regulations require that comments be returned within 15 working days (3 weeks) of when the document was

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<sup>9</sup>The Commonwealth of Virginia, in its recently adopted state Minerals Management Plan, has taken a somewhat novel approach to the review process that has several points to recommend it. For any competitive sale of state oil and gas rights, the major environmental review is conducted between the lease sale and award of the lease, during which detailed plans of the high bidder are subject to scrutiny. When an application is first received, it is reviewed within state government, lease terms and stipulations are formulated, and the lease sale is held. The high bidder is then given six months to submit to the state's Council on the Environment an EIS addressing the detailed plans of the bidder. This EIS is reviewed by state agencies, local governments, and the public after which the Council determines whether the proposed activity is acceptable and what additional restrictions, deletions, and/or mitigating measures must be incorporated into the lease or permits.

The great advantage of this approach is that the environmental review that is conducted before the lease is executed and the state committed can be done on a very detailed proposal and with the identity of the proposed lessee known. Lease stipulations and conditions can be far more detailed and better tailored to the proposed activities than they ever could be under an OCS-like system. However, there are major disadvantages as well. There will be substantial uncertainty before the sale as to the cost of the additional restrictions imposed in the second review phase, leading to lower bids. In addition, the successful bidder must bear the costs of EIS preparation (and state sale costs in the Virginia system) even if the lease is not awarded, which may scare bidders away, particularly small firms who cannot risk such costs.

It is felt that the disadvantages of this approach outweigh the advantages. Under the process outlined in the text, with proper planning the state should be able to attach sufficient safeguards to the lease so as to achieve, in combination with post-sale permitting requirements, most of the environmental protection afforded by the Virginia system, while obtaining more extensive pre-sale exploration, more competition, and higher government revenues.

first submitted for public review. Comments received are forwarded to the sponsoring agency, in this case NRCD.

For review of an oil and gas leasing proposal, standard clearinghouse review procedures are deficient in four respects:

(a) Clearinghouse review does not include federal agencies. Since several federal agencies will be intimately involved in post-sale development decisions, it is essential that their comments be solicited at this stage and potential problems resolved. Review copies should be sent directly by NRCD. The mailing list should include, among others, the U.S. Fish and Wildlife Service, National Marine Fisheries Service, Coast Guard, Department of Defense (including both the Corps of Engineers and services with land or facilities nearby), and, depending on location, the National Park Service, U.S. Forest Service, and Minerals Management Service. In light of counties' regulatory authority mentioned earlier, copies should be sent directly to affected counties as well.

(b) The 15-working day time limit on EIS review is not sufficient for such a complex issue. The clearinghouse regularly negotiates longer review periods with the sponsoring agency. For South Atlantic OCS Sale 78 in July of 1983, North Carolina requested that the review period for the draft EIS be extended from 45 to 60 calendar days. This latter figure seems appropriate for a state EIS on leasing as well.

(c) Public notice through the Environmental Bulletin is not sufficient. The Bulletin simply does not provide adequate public exposure. Announcement of the leasing proposal and draft EIS availability should also be published by NRCD in one or more local papers in the project area and in the Raleigh News and Observer. Non-governmental organizations, such as environmental groups, chambers of commerce, and appropriate industrial or trade associations (e.g., N.C. Petroleum Council, N.C. Fisheries Association) should be contacted by NRCD and sent copies individually.

(d) One or more public hearings should be held in the project area, and possibly in Raleigh as well. Public hearings are optional under SEPA regulations but should be standard for oil and gas lease sale proposals.

It might also be appropriate for the state to publish notices in oil and gas trade journals announcing availability of the draft EIS and inviting comment. These would also serve to alert industry to the possibility that leases may soon be issued in North Carolina waters.

Upon receipt and review of these comments by the working group, a recommendation is made to the Secretary either to proceed with the project and prepare a final EIS and notice of sale, or to reject the proposal. At the same time, the Office of Coastal Management is reviewing the comments and its own coastal management plan (state guidelines and local land use plans) to make a consistency determination, which may involve negotiation with other members of the working group.

Secretarial Decision and Notice of Sale. Based on the results of this review and any task force recommendations, the Secretary must decide whether to approve the lease sale and on what terms. On what grounds should the decision be made? G.S. §146-8 requires only that disposition be "subject to all rights of navigation" and that it "be deemed wise and expedient by the State and to the best interest of the State." In other leasing programs the authorizing statutes and regulations provide administrators with no more guidance. Most leasing legislation establishes some program objectives or policy, but explicit decision criteria are either completely lacking or amount to the requirement that leasing be on such terms as are "in the best interests of the state" (Alaska) or are "just and proper" (Mississippi).

For the sake of the public, the state employees involved in the review, and the Secretary, it may be helpful to at least make explicit what factors should be considered in the decision, without making any attempt to specify how weights should be assigned or what levels of risk are justified. It is recommended that program rules state that the Secretary, in making a decision, will consider among other things the effect of such lease(s) on:

- the quality of the natural environment, including air, surface, and groundwaters, and terrestrial and aquatic life;
- cultural resources;
- recreational resources and activities;
- commercial fishing, tourism, and other industries at risk;
- navigation, shipping, and other transportation;
- socio-economic conditions in the project area, including the industrial base, employment, housing, and the supply and use of public services;
- the potential for discovery of commercial quantities of oil or gas;
- energy supplies, the balance of payments, and national security; and
- the state treasury and the natural resource conservation and development projects that might be funded with sale proceeds.

If the Secretary determines a lease sale to be in the public interest, a final EIS and a proposed notice of sale are prepared. The notice of sale serves to notify all interested parties of the Secretary's decision as to what will be offered and on what terms, and provides information to bidders on how to submit bids. The notice should contain, at a minimum, a description of the areas to be offered, a summary of the lease terms (with copies of the lease available upon request), the stipulations to be attached, and information on bidder eligibility, the bidding variable, minimum acceptable bids (if any), the date of sale, where and how bids should be submitted, and conduct of the sale. Several states (Texas, Mississippi, Alabama, and Alaska) also use the notice of sale to notify bidders of limitations that may or will be imposed on development during the permitting stage. It is strongly advised that North Carolina do likewise, for reasons of both fairness and, by reducing uncertainty of regulatory costs, higher bids, at lease in the long run.

In Alaska the decision-maker (Director of the Division of Minerals and Energy Management) also issues a document known as the Preliminary Analysis of the Director. Totalling 40-50 pages of text, it sets out the findings of the division with regards to the potential effects of the sale and the mitigating measures needed to limit these effects to acceptable levels, and specifically addresses the question of whether the sale is in the state's best interests. In part, this is necessary because the Alaskan environmental document does not represent the thinking of the sponsoring agency, as it does in other programs. But in the interests of public understanding and open government, it might be useful if the North Carolina notice of sale were also prefaced by a short (2-5 page?) but specific explanation of why the Secretary decided as he did. Such a statement could preface the final EIS instead.

Since under G.S. §146-8 the Department of Administration and the Governor and Council of State must approve any lease, and since with competitive bidding the terms must be finalized before the lease sale, the notice of sale at this point should be sent to these officials for their approval. If the State Property Office has been included in the deliberations, if the Department of Justice has been consulted or relied upon for lease preparation, and if state agencies and other groups have been duly consulted, it is unlikely that any major objections will arise at this stage.

Several programs permit additional review and comment on the proposed notice of sale. Alaska and California provide for a period of public comment on the notice, while the OCS program accepts comments only from state governors and, through them, affected local governments. In Texas, Louisiana, Alabama, and Mississippi there is no provision for review of the sale notice. The advantage of such a comment period is that it gives the public the opportunity to comment on exactly how the Secretary weighed various considerations and interpreted "the best interest of the State" in reaching a decision. It gives the Department a chance to test its decision before becoming committed, and it hopefully strengthens the impression that decision-makers have been accessible and considerate of all comments. The disadvantages are that it lengthens the review process and often results only in a reiteration of points previously made.

It is recommended that the state permit public comment on the proposed notice of sale, and that it be sent out for review via a mailing list developed during review of the draft EIS. Department of Administration and Council of State review would then follow. After their approval, the Secretary would issue the final notice of sale and invitation to bid. Notice should be published not only in North Carolina but also in journals and newspapers more visible to the oil and gas industry, as extensive advertising can only benefit the state at this stage.

It may be of interest to note some of the major features of review procedures in other programs (Table 5-4, Figure 5-1). The attitudes of Louisiana and Texas with regards to their limited pre-sale review are that extensive review is best left to the permitting stage. Such attitudes may be justified by the long history, familiarity, and acceptance which the oil and gas industry enjoys in these states.

Table 5-4

## Major Features of Review Procedures in Selected Leasing Programs

	<u>Review by other state and federal agencies?</u>	<u>Public review?</u>	<u>Public hearing?</u>	<u>Environmental document?</u>
Alabama	X	X	X	
Alaska	X	X	X	X
California	X	X	X	X
Louisiana				
Mississippi	X	X	X	
Texas	X			
U.S.	X	X	X	X

Appeals. One of the rules for submerged lands leasing adopted in 1976 entitled a rejected applicant to a departmental hearing under 15 NCAC 1B .0200.<sup>10</sup> The question of appeal rights under the new procedures described above has not yet been addressed.

Rule 15 NCAC 1B .0202 ("Availability of Contested Case Hearing") states that: "The agency shall commence a contested case hearing procedure if any of the following occurs:...(3) A party who has exhausted or waived any available prehearing processes requests a contested case hearing after the agency has, in any matter other than rulemaking or a declaratory ruling proceeding: (A) issued a complaint, citation, response to an application or request, or other preliminary determination. . . ." While this language appears to entitle a rejected applicant to a hearing, it is argued that this requirement is not or should not be relevant. The "application or request" referred to is assumed to be an application or request to conduct regulated activities on private property, where denial results in a limitation of private property rights. In regards to leasing, it is public property at stake, and the government is no more accountable to the applicant for its decision than it is to any other interested party. To grant all parties appeal rights would be to virtually ensure that every leasing decision would be followed by a hearing. Furthermore, once the application reaches the EIS stage with clearinghouse review and public hearings, there is ample opportunity for all interested parties to be heard. Before this point an applicant may be turned down without an opportunity to be heard, and if this is the case, a request for a hearing would

<sup>10</sup>15 NCAC 5E .0005.

have some merit. No other leasing program entitles the aggrieved applicant to challenge the final decision. It is recommended that in North Carolina a contested case hearing on the Secretary's leasing decision be granted at the discretion of the Department.

Timing. A reliable timetable for review is important for instilling confidence in the process, for ensuring that all tasks are coordinated properly, and for protecting the interests of all parties. Most states establish schedules of events for individual sales. Some of these are highly elaborate; a typical in-house sale process timeline used in Alaska lists 94 separate events over a four-year span. Typical schedules for sale milestones in the various leasing programs are shown in Figure 5-1.

It is recommended that, at the time Land Resources forwards the application to the Secretary for his approval of further review, the Division also submit a proposed review timetable for the Secretary's approval. A reasonable time-frame for the review process is suggested in Table 5-5.

How long after the final notice is issued should the sale date be set? Figure 5-1 shows that in six of the seven programs examined, the final notice is issued 1-2 months before the sale. Most programs require a minimum notice of 30-60 days. Notice for the Point Conception sale in California was issued seven months before the sale was to be held to give both the State Lands Commission and the companies time to prepare. Virginia's new procedures and a proposed revision of Delaware's leasing statutes would both allow up to 18 months between the final notice and the sale.<sup>11</sup>

Before a sale, companies must have time to plan and conduct geophysical surveys (or buy them "off the shelf"), interpret the results, and prepare a bid. One industry source indicated that in an area where no geophysical surveys have been conducted previously, this process will take at least a year; if some surveys already exist, this process can be reduced to six months. Where the final notice is issued 1-2 months before the sale, industry must make the often sizable investment in exploration before there is assurance that the tracts will be offered. Industry is generally willing to do this because most of these programs have a fair amount of predictability. While doubts may remain regarding the specific terms and conditions of sale, there is a high probability that a large proportion of the tracts under consideration will ultimately be offered.

Currently there is no such predictability or assurance in North Carolina. Given the importance of the fishing and tourist industries, the public concern for environmental quality, the lack of recent experience with oil and gas operations, and the state's recent positions on OCS sales, it is possible that

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<sup>11</sup>Commonwealth of Virginia, State Minerals Management Plan, prepared by the Department of Conservation and Economic Development, Division of Mineral Resources, in cooperation with the Department of General Services, Division of Engineering and Buildings (n.p., 1983); Robert G. Doyle, "Review and Revision of Delaware Mineral Laws, Including Draft Legislation," prepared by the Delaware Geological Survey under contract to the Office of Management, Budget, and Planning (Newark, Del., 1981).

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Table 5-5

Suggested Timetable for Proposed Review Process (EIS Option)

<u>Time (in months)</u>	<u>Events</u>
1	Land Resources receives application, reviews with assistance from others, and rejects, defers, or makes recommendation to secretary.
1	Secretary appoints working group; group considers proposal, consults others, recommends to: reject, approve with negative declaration, or approve with EIS.
4-6	EIS written
2	Draft EIS sent to Secretary, circulated within Department, revised as appropriate and sent to clearinghouse.
2	Clearinghouse circulates, also sent to federal agencies; public notice and hearing(s)
2	Comments reviewed; EIS revised; Final EIS and proposed notice of sale issued.
2	Proposed notice circulates; comments received; notice revised if necessary; approval obtained from Administration, Governor and Council of State; final notice issued.
14-16 months	Total from application to final notice of sale

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only a small percentage, if any, of the acreage applied for will be offered, at least until experience with leasing increases. Under these circumstances, exploration undertaken before the final notice may very well be wasted. Fearing this, and given only 1-2 months between notice and sale, companies may choose not to participate or may explore only sparingly. To eliminate the possibility of wasted exploration and thereby improve economic efficiency, reduce uncertainty, encourage greater industry participation and increase bids, the state should give serious thought to timing the sale so that companies have time to conduct adequate exploration programs after the final, or at least proposed, notice of sale. Interested companies can best advise on the time needed, but it would appear to require 6-12 months after the proposed or final notice.

There are disadvantages with this timing as well. The sale is postponed that much longer and companies may lose interest or the market may change.

The applicant, who must explore early to know which tracts to apply for, is penalized. Pragmatically such timing also gives groups seeking to disrupt the sale that much longer to marshal their forces and get to court. Nevertheless, allowing sufficient time for exploration after a sale notice seems to have sufficient merit to deserve testing.

#### An Alternative Leasing Process

If the state should decide instead to pursue a more aggressive approach, with active promotion of oil and gas development, there are several changes that can be made in the procedures outlined above to accomplish this without sacrificing environmental safeguards. In general, the state should consider adopting more of an OCS-like process. This might include:

(1) a clear announcement by the state of its intent to hold a lease sale (presumably following a finding that such a sale is in "the best interest of the State" and that development of sale leases could be done under existing environmental laws);

(2) a systematic effort to solicit expressions of industry interest, through a call for nominations or similar means;

(3) encouragement of geological and geophysical exploration of state waters on an on-going basis, independent of specific sales; and

(4) assignment to one office or committee of the responsibility to guide lease sale proposals through the review process and to promote sales to the full extent allowed by other program objectives and by existing environmental and other laws.

Economic incentives are another powerful way to promote exploration and development; these are discussed in section 5.6.

#### 5.3 Protection of Environmental and Economic Resources

Protection of the natural environment and of existing economic activities will be a major focus of any leasing program. The quality of the coastal environment is held in high regard in North Carolina and largely determines the success of the fishing and tourist industries, two of the mainstays of the coastal economy.

How such protection is achieved is the subject of this subchapter. Our concern here is with general strategies for protection, and not with the specific details of individual measures, which are better left to NRCD personnel. The subchapter addresses five topics: (a) the various avenues or vehicles available to the state for achieving environmental protection; (b) approaches to reducing general types of impacts; (c) organization and research for environmental protection; (d) the need for pre-sale review and coordination; and (e) leases of privately owned submerged lands.

## Avenues for Protection of Environmental Resources

Five avenues or vehicles for protecting environmental and economic resources from the undesirable impacts of oil and gas development are available to the state. These are:

1. the decision of which areas to offer for lease;
2. eligibility criteria for bidders;
3. lease terms and stipulations;
4. regulations on operations conducted pursuant to the lease; and
5. other laws, regulations, and permits.

The first four of these are available to the state in its role as a landowner, with resources to sell, while the last stems from the state's authority to regulate public and private activities under the police power.

Decision of what areas to offer for lease. The decision not to offer an area for lease provides the most basic and reliable protection available. If development of an area, regardless of how it is conducted, would result in adverse impacts or risks greater than potential benefits, this decision is appropriate. However, since refusal to lease postpones indefinitely the benefits that might accrue from development, this decision should only be used as a last resort, after the state has determined that all other available measures are inadequate to protect the resource.

It is important to keep in mind here the distinction between leasing and drilling. A lease does not give the lessee permission to drill at any point within its boundaries nor is such permission necessary to develop the tract's hydrocarbon resources. Depending on economic considerations and reservoir, hydrocarbon, and well characteristics, a single well may be used drain tens or even hundreds of acres. In addition, directional drilling allows bottom hole locations to be reached hundreds or thousands of feet horizontally from the drilling rig.<sup>12</sup> The combined result is that the oil and gas resources underneath large areas may be removed from a single surface location. Directional drilling has technical limits, of course, and there are certain disadvantages to its use: it is costlier, more time consuming, riskier, and makes subsurface geological interpretation and formation evaluation more difficult than do vertical boreholes.<sup>13</sup> The point to be made is that, where

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<sup>12</sup>See, e.g., B.E. Cox and W.A. Bruha, "Curved Well Conductors and Offshore Platform Hydrocarbon Development," OTC Paper 2621, pp. 19-29 in: Eighth Annual Offshore Technology Conference Proceedings, Vol. 3 (Dallas: OTC, 1976).

<sup>13</sup>See American Petroleum Institute, API Recommended Practice for Drill Stem Design and Operating Limits, 10th ed., Publication API RP 7G (Dallas: API, 1981), Section 6: "Limitations Related to Hole Deviation"; California State Lands Commission, "Staff Report on Current Status of Proposed Pt.

surface location is a concern, a lease with surface restrictions may permit the oil and gas resources to be extracted while achieving the same measure of protection as a decision not to lease.

This is just one example of the factors the state should consider. For each impact, the relevant question should be: are there measures available, be they certain technologies, restrictions on operations, or other means, that can limit adverse impacts to acceptable levels without withdrawing the area from availability altogether?

Two levels of this type of review are possible. It may be done in connection with a specific lease proposal, with consideration limited to the area covered by the application. Or at any time, irrespective of pending applications, the state may wish to consider establishing a leasing moratorium within a specified area, be it a few acres or the state's entire jurisdiction. The purpose would be to announce to industry that the state will not approve applications in these areas under any conditions, and so save industry the cost of preparing those applications and the state the time and effort needed to individually review them. The disadvantages of such a moratorium are that (a) it is an additional administrative chore that may be time wasted if the policy is never needed, (b) time limits or conditions under which the policy would be reviewed must be set, and (c) the state may include areas without examining alternative restrictions that offer the desired level of protection.

Leasing moratoria tend to be tools of the legislative rather than the executive branch. The Alaskan and Californian legislatures and the U.S. Congress have all passed laws prohibiting leasing on portions of their respective jurisdictions.<sup>14</sup>

It is recommended that the state not consider a moratorium separately but that the question of a moratorium be raised as a natural response to any rejected application if the reasons for the rejection so indicate. Should the state wish to establish a formal leasing moratorium in a certain area, there should be a review with public hearing to establish where, how long, and why. The moratorium could even be promulgated as a rule.

Eligibility criteria for bidders. Eligibility criteria for bidding are discussed at length in Section 5.6. They are mentioned here because it is conceivable that one criterion be that a company have a good environmental record, or more specifically, that the company have shown good faith in complying with environmental laws and regulations. This option presents two difficulties. The definitions or standards needed to apply such a criterion fairly would be difficult to formulate. Moreover, lessees often hire drilling contractors, and the environmental record of the lessee may bear little relation to that of the contractor. However, liability is not necessarily

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Conception/Pt. Arguello Oil and Gas Leasing Program," Dec. 15, 1982, mimeo, p.49.

<sup>14</sup>Alaska Stat. §38.05.184; Calif. Public Resources Code §§6870, 6871.1, 6871.2; 43 U.S.C. §1340(h).

transferred from the lessee to the driller, so that the environmental record of the lessee would reflect that of the contractors it hires and could be considered by the state. A more feasible option might be to require state approval of the driller before the lessee could begin operations. Such approval might be contingent, at least, on the driller's having had experience in environments similar to that of the lease, and if suitable criteria can be devised, on the driller's having shown good faith in complying with drilling regulations, environmental permits, and the like.

Lease terms and stipulations. Provisions for environmental protection can be inserted as terms in the lease itself or attached as stipulations. The lease should be a fairly standard document that can be used with minor modifications throughout the state's jurisdiction. Stipulations, on the other hand, are attached to the lease on a case-by-case basis and are designed to deal with environmental or other problems specific to that tract.

Perhaps the most important lease provision from an environmental perspective is the one that binds the lessee to compliance with the leasing statute, its regulations, and all other applicable statutes and regulations. If an environmental statute is violated, this provision makes the lessee liable not only for the penalties listed in the statute, but for loss of the lease as well. Other provisions of the lease may address such concerns as safety requirements, plans of operation, surety bonds, and property removal (see Appendix F).

Stipulations are used to address a wide variety of subjects, and their use in a given situation is limited only by the creativity of the authors and the willingness of companies to bid on the product to which they are attached. Some stipulations work on a contingency basis, with the lessor authorized to require certain measures if a study so indicates or a specified event or discovery occurs. The best way to describe how stipulations may be used is to provide some illustrations (Table 5-6).

Operating regulations and requirements. In many programs the leasing agency is authorized under state law to adopt regulations governing lease operations. While most of these requirements could be included in the lease, not doing so keeps the lease form simple and allows the regulations to be amended as technology changes and our environmental knowledge improves. Such regulations may contain specific environmental safeguards, or they may establish procedures and standards for approval of certain operations; the Minerals Management Service's OCS regulations (30 CFR 250 and OCS Operating Orders) provide several examples of each. Topics that might be covered by such regulations include drilling requirements, oil spill contingency plans, plans of operations, environmental reports, and worker safety requirements, among others.

What operating regulations a program adopts will depend in part on whether other agencies already regulate the target activities. Most states, for instance, have oil and gas boards that regulate drilling operations, so most leasing agencies leave this function to them.

The advantage of such regulatory authority is that, because the operations are on state lands, the grant of authority is much broader and the

Table 5-6

Examples of Stipulations Attached to Offshore Oil and Gas Leases

<u>Subject of Stipulation and Recent Sale in Which Employed</u>	<u>Description of Stipulation as Used in that Sale</u>
Geological (OCS Sale 56)	Requires lessee to demonstrate that operations can be conducted safely on portions of tracts identified as being susceptible to mass movements of sediment.
Cultural Resources (OCS Sale 78)	Allows lessor to require remote sensing surveys for cultural resources and protection for any resources located.
Biological Resources (OCS Sale 78)	Requires surveys and protection for hard bottom areas and protection for other significant biological resources.
Fisheries Training Program (Calif. Pt. Conception Sale*)	Requires lessee's supervisors and vessel operators to become familiar with commercial fishing operations and potential conflicts with the fishing industry.
Oil Spill Response Capability (Calif. Pt. Conception Sale)	Establishes lessee's responsibilities for maintaining an oil spill response capability and for funding related programs.
Drilling Muds and Cuttings (Calif. Pt. Conception Sale)	Prohibits discharge of drilling muds and cuttings into the marine environment.
Subsea Completions (Calif. Pt. Conception Sale)	Allows lessor to require subsea completions rather than fixed platforms wherever specified factors so indicate.
Seasonal Drilling Restriction (Alaska Sale 39)	Requires lessee to restrict drilling activities during fall bowhead whale migration and to fund appropriate studies at state's direction.
Military Areas (OCS Sale 78)	Limits government liability for military accidents and requires operational agreements and control of electro-magnetic emissions for tracts subject to joint use by military.
Undetonated Explosives (OCS Sale 78)	Requires lessee to conduct additional surveys if lessor believes unexploded ordnance exists in lease area.

Table 5-6 (continued)

<u>Subject of Stipulation and Recent Sale in Which Employed</u>	<u>Description of Stipulation as Used in that Sale</u>
Transportation (OCS Sale 56)	Requires transportation of petroleum by pipeline rather than tanker, wherever practicable, and establishes certain guidelines for the use of both.
Labor Requirement (Calif. Pt. Conception Sale)	Requires that lessee's labor force be comprised of U.S. citizens and permanent resident aliens.
Special Studies (Calif. Pt. Conception Sale)	Establishes lessee's financial responsibility for specific studies as the state may require.

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\*California stipulations are technically called "Special Operating Requirements" and are listed in Exhibit C of the lease.

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topics that may be addressed less restricted than under standard environmental statutes (including oil and gas conservation acts). As a result, leasing agencies often use such regulations to "fill in the gaps" so to speak, i.e., to address concerns that the existing regulatory scheme does not. The need to review the responsibilities and capabilities of the different regulatory agencies in a state and to coordinate their responses with that of the leasing agency is evident.

A problem arises in North Carolina in that the authority to adopt such regulations is vested in the Department of Administration, not NRCD. N.C. Gen. Stat. §146-8 makes no mention of rules. Section 146-2 states, "The power to manage, control, and dispose of . . . submerged lands is hereby vested in the Department of Administration . . .;" and confers upon Administration the power "to adopt such rules and regulations as it may deem necessary to carry out its duties under the provisions of this subchapter." Under these circumstances, the state would seem to have three options:

(1) Not attempt to regulate lease operations beyond what is provided for in lease provisions and existing regulatory statutes. Some requirements can be included in the lease itself; Alaska, for instance, includes requirements for the submission and approval of a plan of operations in the lease, but regulations elsewhere expand on it. This approach works well for simple requirements but less so for complex ones, particularly if they involve lengthy review procedures.

(2) Promulgate regulations by the Department of Administration. This is not advisable for several reasons. The types of regulations envisioned deal with oil and gas technologies and environmental impacts and mitigation; the expertise to promulgate and enforce these regulations already exists in NRCD

for the most part, and not in Administration. Moreover NRCD already has responsibility for developing the lease proposal and for granting most of the permits needed to develop the lease.

(3) Request the General Assembly to amend §146-8 to provide NRCD with appropriate rule-making authority. The amendment might read: "Other provisions of this subchapter notwithstanding, the Secretary of the Department of Natural Resources and Community Development may adopt and enforce rules and regulations governing mineral operations conducted pursuant to a sale, lease, or other disposition under this section."

Other statutes, regulations, and permits. Most of the potential impacts of oil and gas development are addressed by existing statutes, regulations, and permit requirements. These are reviewed in Chapter Three and Appendix E. The conditions attached to issuance of some of these permits, particularly the CAMA Major, NPDES, and Sections 10/404 permits, will be key to the levels of impact generated by lease operations.

#### Approaches to Reducing Specific Types of Impacts

In Appendix D, the major environmental impacts of oil and gas activities were reviewed. It is appropriate now to examine each of these categories in terms of how North Carolina might respond to potential impacts. Table 5-7 lists both existing statutory authorities and approaches other programs have taken that North Carolina might consider. Since the state could respond to any of these impacts (except those from geophysical exploration) by refusing to lease the area, this option is not listed. Chapter Three and Appendix E provide details on the laws and permits mentioned.

#### Research for Environmental Protection

During the course of review many questions may be raised which cannot be answered immediately but which are amenable to research. Studies programs to address these questions are integral parts of some leasing programs, particularly those of California and the U.S. Such studies may be of several types: geologic and geophysical surveys to estimate hydrocarbon potential; geohazard and cultural resource surveys to identify these types of site specific risks; characterization studies of biota found on the tract(s); fates and effects studies of discharged substances; and monitoring studies to detect environmental changes during oil and gas operations.

There are four possible sources of funding for these studies: direct legislative appropriations, the companies themselves, existing grant programs (Coastal Energy Impact Program, Sea Grant, Water Resources Research Institute, etc.), and regular agency budgets. A distinct studies program, focussed specifically on leasing questions and funded at least initially by the General Assembly, will provide the best chance that the studies will be well coordinated and that the highest priority studies will be funded first. Lessees might be required to reimburse the state for pre-sale studies, or alternatively, the cost might be taken out of sale proceeds. These proceeds might also provide a source of long-term funding.

Table 5-7. Measures for Reducing the Impacts of Petroleum Development in North Carolina's Submerged Lands.

<u>Impact Category and Subcategory</u>	<u>Measures Available for Use in North Carolina</u>
Geophysical Exploration	Geophysical exploration permit* (needs improvement) CAMA permit* (in some cases) See also navigational hazards, below
Dredging and Filling	
general environmental disturbance	\$10, \$404 permits from the Corps,* NEPA * State dredge and fill permit* CAMA major permit* Easements from DOA for platforms, pipelines, and other facilities* Biological resources stipulation (OCS Sale 78)
disturbance of cultural resources	Corps permits,* National Historic Preservation Act of 1966* CAMA major permit,* G.S. §121-12a,* Archives and History Act* Cultural resources stipulation (OCS Sale 78)
Presence of Structures and Boats	
navigational hazards of structures	\$10 permit from Corps* Aids to Navigation on Artificial Islands and Fixed Structures (33 CFR 67)* Easements from DOA for platforms and other fixed facilities* Navigational charts, Marine Broadcasts, and Local Notices to Mariners*
navigational hazards and conflicts of increased traffic	Navigational charts, Marine Broadcasts, and Local Notices to Mariners* Fisheries Training Program stipulation (OCS Sale 42, Calif.)* Alaska stipulation restricting surface use under certain conditions Arbitration procedures for settling claims (Calif.)
trash and debris	Required marking of materials (OCS Order 1) Gear loss funds (U.S., Louisiana)
loss of access	CAMA major permit* Pipeline regulations and stipulation (U.S.)
military conflict	Coordination with Department of Defense
visual impact	Subsea completions stipulation (Calif.)
Oil spills	
prevention	Drilling regulations under Oil and Gas Conservation Act* (need improvement; see, e.g., OCS Operating Orders, regulations of states' Oil and Gas Boards or equivalent) Other operating regulations (30 CFR 250 and OCS Operating Orders)
clean-up	Operator oil spill contingency plan required by regulation, stipulation, or permit condition (OCS Order 7) Oil spill response capability stipulation (Calif.) Federal contingency plans (national, regional, local) under Federal Water Pollution Control Act §311, as amended* State contingency plan under N.C. Oil Pollution and Hazardous Substances Control Act of 1978*
liability and recovery for damages	Federal Water Pollution

Table 5-7. (continued)

<u>Impact Category and Subcategory</u>	<u>Measures Available for Use in North Carolina</u>
Oil Spills (continued) liability and recovery for damages	Federal Water Pollution Control Act §311, as amended* N.C. Oil Pollution and Hazardous Substances Control Act of 1978* compensation fund (U.S. Offshore Oil Pollution Compen- sation Fund under 43 U.S.C. §§1811-1824) evidence of operator's financial responsibility by bond, insurance, etc. (43 U.S.C. §1815) arbitration procedure for settling claims (Alabama)
Drilling Fluids and Cuttings, Formation Waters, and Other Discharges	Federal Water Pollution Control Act, NPDES permit, and §401 water quality certification* State water pollution control statutes and permits* Regulations for preventing pollution (OCS Order 7) Stipulations on pollution discharges (Calif.)
Air Pollution	Clean Air Act and PSD program* State air quality permit* Regulation or stipulation requiring hydrogen sulfide contingency plan (Alabama, Calif.)
Employment	Labor stipulation (Calif.)

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\*Currently in effect in North Carolina

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Some questions may need to be answered before the state will be willing to consider leasing; these are typically addressed by program directed and funded studies. Other questions may not be critical to the leasing decision itself but do relate to what types of restrictions on operations are appropriate. Studies directed at these questions can be provided for by lease stipulations requiring the lessee to fund or undertake these studies at the state's direction.

#### The Need for Pre-Sale Review and Coordination

The need for consultation and coordination among environmental agencies during lease sale review cannot be emphasized enough. Three reasons for extensive coordination at this stage exist:

(1) The ability of the state, through lease terms and stipulations, to impose virtually any requirement deemed in the public interest on the lessee was mentioned earlier as an important means of protecting environmental resources. Once the lease is signed, this opportunity is lost. It is essential, therefore, that the state make a concerted effort during sale review to anticipate the adverse impacts of the sale and to ensure that they are addressed either by existing or proposed laws and regulations or by lease terms and stipulations. Part of the substantive review of the first lease application should be a thorough review of existing laws and regulations and a program for upgrading them where necessary.

(2) In issuing a lease and accepting compensation for it, the state has implied that it believes the lease can be developed with no unreasonable expenses required beyond the terms and requirements announced in the notice of sale. In the interest of fairness, if nothing else, the state has an obligation to make a good faith effort to identify any major regulatory hurdles to development of the tract.

(3) The higher the risk perceived by industry that additional, unexpected regulatory costs will be imposed on the lessee, the lower the bids (and perhaps the competition) will be. This perceived risk can only be reduced with time. A concerted and visible state effort before the first sale to identify environmental problems and their regulatory solutions may instill confidence in industry and be reflected in sale bids. However, this risk will be reduced in the long run only if the state can establish a track record of not imposing major unexpected costs after the lease is executed, something that can only be accomplished if extensive review and coordination precede the sale.

#### Leases of Privately Owned Submerged Lands

If some private fee simple or mineral interests in submerged lands should be found to be valid (see section 5.4), the state must recognize the possibility that these lands might also be leased for petroleum exploration and development. If this occurs, the state's role will be restricted to that of regulator of activities on private property (the fifth of the five vehicles for environmental protection discussed earlier in this section). Opportunities for some types of restrictions and for control over the rate of leasing will no longer be present. However, existing regulatory statutes, particularly the Oil and Gas Conservation Act, CAMA, the Federal Water Pollution Control Act, and others, provide authority for a substantial degree of control over oil and gas activities regardless of land ownership.

It is therefore recommended that (1) the implications of the findings of the existing Submerged Lands Task Force for private oil and gas leasing be kept in mind, and (2) during the course of review of existing authorities in conjunction with the first lease application, or sooner if needed, state regulatory authority should be reviewed to determine whether it alone is currently adequate to control the adverse impacts of submerged lands petroleum development.

#### 5.4 Area and Rate of Leasing

In considering the leasing of state-owned submerged lands, two of the most basic questions to be asked are: what areas should (or could) be offered for lease, and at what rate should they be offered? There are a number of factors that ought to be included in any consideration of the public interest, and the more significant of these are discussed below:

##### Environmental Sensitivity

Are the areas under consideration environmentally sensitive? Can leasing impacts on these areas be limited to acceptable levels? These are probably the most important questions in deciding whether a tract should be made available for lease, and are discussed in detail in sections 5.2 (The Leasing Process) and 5.3 (Protection of Environmental and Economic Resources).

##### Tract Size and Shape

What is an appropriate size and configuration for a lease tract? In the past it has been North Carolina's practice to lease huge tracts (hundreds of thousands of acres) for exploration, with the lessee retaining the right, upon completion of a producing well, to select and hold blocks of up to 750,000 acres, depending on the lease (Figure 2.3). There are several reasons why tracts this large should not be leased:

- 1) Such a lease eliminates the primary means through which the state can control the rate and location of development. With smaller blocks, the state can slow the pace of development by reducing the acreage let, or speed it up by issuing a number of leases simultaneously, each with its standard requirement that drilling must be begun within the primary term or the lease will be cancelled.

- 2) Large lease tracts transfer all the resources within large areas to the lessees at the agreed upon terms, which in a frontier area may be quite modest. Should a commercial field be discovered, the enhanced value of the lands surrounding the discovery will accrue mostly to the lessees, while with smaller blocks, the state would realize large gains from nearby unleased tracts.

- 3) The cost of leasing such large areas may be sufficient to drive smaller firms out of the market, reducing competition and probably reducing the size of bids on a per-acre basis.

The practice of other programs regarding offshore lease tract size is shown in Table 5-8. Notice that the tracts in all of these programs are less than 6,000 acres. Industry has generally expressed satisfaction with a 5,000-6,000 acre tract size.

Several factors should be considered in choosing an appropriate tract size or size range. On the one hand, tracts should be small enough to allow the state to retain a fair degree of control over the location and rate of

Table 5-8

## Lease Tract Size in Selected Leasing Programs

(all tract sizes in acres)

<u>Program</u>	Maximum Tract Size Established by:		Tract Sizes in a Recent Sale: <sup>1</sup>	
	<u>Statute</u>	<u>Administrative Policy</u>	<u>Range</u>	<u>Average</u>
Alabama	5200		29-5164	3709
Alaska	5760		3824-5760	5108
California	5760		4898-5742	5118
Louisiana	5000	2500	282-2503	1608
Mississippi	6000	2880	1177-2880	2563
Texas		1440	5-1440	945
U.S.	5760 <sup>2</sup>		5693	5693

<sup>1</sup>Alabama 1981 offshore sale; Alaska Lease Sale 39; California Point Conception Sale; Louisiana 3 March 1983 Sale; Mississippi Lease Sale No. 1; Texas 5 October 1983 Sale, Group IV; U.S. OCS Sale 56.

<sup>2</sup>"unless the Secretary finds that a larger area is necessary to comprise a reasonable economic production unit" (43 U.S.C. §1337(b)).

development, to provide the state with some of the benefits of land values increased by a discovery, and to keep tract bonuses sufficiently low to encourage competition. On the other hand, tracts should be large enough to compensate the lessee for the riskiness of the investment. A case can be made that in low potential wildcat areas such as eastern North Carolina, relatively larger tracts are needed to accomplish this. Given the experience of other programs, it is suggested that the state adopt as standard practice a lease tract size in the 5,000-6,000 acre range, but that, on a case-by-case basis, industry be given the opportunity to demonstrate that a larger tract size would be more suited to the particular circumstances of the area being considered.

How should lease tract boundaries be determined? The state clearly has an interest in an orderly configuration that facilitates the leasing of

adjacent areas and the re-leasing of quitclaimed leases, and that minimizes problems between adjacent lesses. The simplest pattern is a square or rectangular grid. The grid used in the OCS program consists of square blocks 4800 meters on a side, each containing 2304 hectares (5693 acres). Block boundaries are defined in terms of X and Y coordinates of the Universal Transverse Mercator (UTM) Grid System, and the location and boundaries of these blocks are shown on OCS Official Protraction Diagrams issued by the Minerals Management Service. These blocks are everywhere square and identical in size, except in two circumstances: at the territorial boundary between state and federal waters, where block boundaries may be irregular, and along certain lines of longitude where, because of an artifact in the UTM grid that results from attempting to place a square grid on the earth's curved surface, columns of blocks adjacent to particular longitudinal lines slowly narrow in width as one moves northward. One such line of longitude is 78° W, which occurs just west of Cape Fear.

Where a partial block occurs on the OCS, depending on its size it is either leased separately or combined with an adjacent block to comprise a unit large enough for economical development. Tracts offered for lease may also be less than a full block where a portion of the block is excluded for environmental or other reasons, such as the existence of a marine sanctuary.

Five of the six states examined use a grid system to some extent, though they often subdivide the larger blocks, sometimes into irregularly shaped parcels. Texas and Louisiana rely on an extension of the OCS grid into state waters. Alabama uses a 15,000 ft. grid, resulting in blocks of 5164 acres; Mississippi uses a three-statute-mile grid with blocks of 5760 acres, and Alaska uses an extension of its township and range survey to define offshore tracts of one to nine sections (each section being 640 acres, or one square mile). California was guided by three considerations in dividing the 40,000 acre Point Conception sale area into tracts. (1) a statutory limit on tract size of 5760 acres; (2) staff interest in keeping tract boundaries from crossing identified geologic structures (such a configuration, they claimed, would provide for simpler reservoir control, the potential for reduction in number of development programs, greater ease in program administration, probably fewer platforms and associated facilities, and less accounting problems); and (3) industry interest in constructing boundaries so that the corners coincide as much as possible with the corners of adjacent federal leases, so as to reduce the difficulties in unit or cooperative development should any reservoirs cross the state/federal boundary.<sup>15</sup> The result was the tract configuration shown in Figure 5-4.

Though the use of promising geologic structures to define tract boundaries has merit, it also has disadvantages. Such a scheme requires the acquisition of a substantial amount of non-proprietary geologic data, something California was willing to buy but most states are not. Even if the data are acquired, there is no guarantee that the state's predictions of reservoir location are correct. Furthermore, unitization was designed to deal with precisely these problems. Such boundaries also result in irregular tract parcels that may not

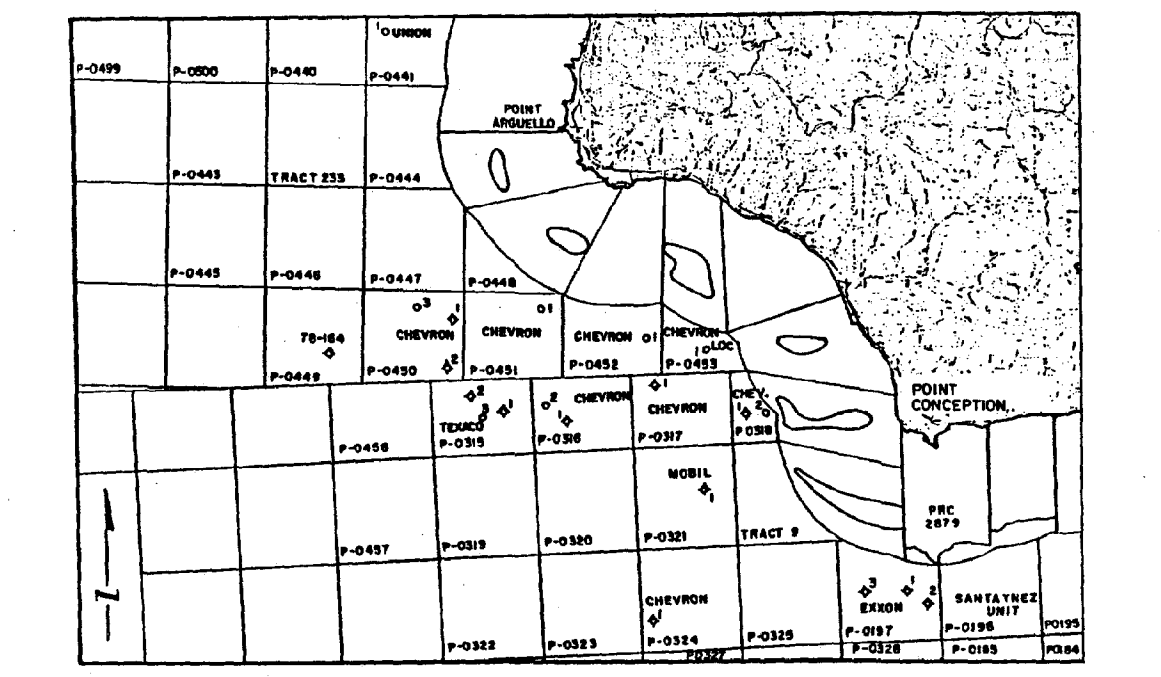
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<sup>15</sup>California State Lands Commission, "Staff Report on Current Status of Proposed Pt. Conception/Pt. Arguello Oil and Gas Leasing Program," Nov. 29, 1982, mimeo, pp. 24-25.

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Lease Tract Configuration for California's Point Conception Sale

The 40,000-acre sale area between Point Arguello and Point Conception was divided into 8 tracts. Potential petroleum bearing structures and existing state and OCS lease tracts and lessees are identified. (From California State Lands Commission, "Staff Report on Current Status of Proposed Pt. Conception/Pt. Arguello Oil and Gas Leasing Program," Dec. 15, 1982, mimeo, p. 85.)



create many problems where two sides of the tracts are already defined (as in California), but might create administrative headaches in large open water areas like Pamlico Sound.

A grid system, particularly one that is compatible with the OCS grid, has much to recommend it. Boundary selection requires and assumes no geologic knowledge. The entire area is automatically divided into compact, manageable blocks that facilitate their leasing and re-leasing. The number of leases adjacent to any single lease is kept relatively small, making unit operations simpler. Coordination with OCS lessees at the state-federal boundary is also easier.

In 1978, in response to concerns that previous North Carolina lease tracts had been too large, the Department of Natural Resources and Community Development began the process of extending the OCS grid into North Carolina waters with the intention that future leasing be done in multiples of these 2,304-

hectare blocks. The Land Resources Information Service is currently engaged in this work.

The continued use of this grid for defining lease blocks is recommended. At some point in the future, the state may wish to consider subdividing these blocks, as is done in several other states. For now, however, it is recommended that tracts of 2304 hectares be offered for lease, except where industry can demonstrate that tracts comprised of 2 or more of these blocks are preferable. As with the OCS program, partial blocks may be leased separately or attached to an adjacent block.

One final point. In Louisiana, companies may submit bids for portions of offered tracts. Not only does this create problems in evaluating bids (discussed later), but it may also create the irregular boundary problems that a grid system is designed to alleviate. None of the other programs permit bids on less than a full tract,<sup>16</sup> and North Carolina should not either.

#### Clear Title

There are two sources of potential title conflict regarding the state's ability to lease oil and gas rights in a specific parcel. First, there may be disagreement over the location of the boundaries between the state's lands and those of the federal government, adjacent states, and upland owners. Secondly, there may be disagreement over whether the state has disposed of certain interests in these lands, and what rights regarding use of the surface the state has retained and can be conveyed to a mineral lessee.

Boundaries. For the Atlantic states, including North Carolina, the boundary between state and federal jurisdiction over the seabed was established by Congress in the Submerged Lands Act of 1953 as three geographical or nautical miles seaward of the coastline, measured from ordinary low water.<sup>17</sup> This boundary was subsequently upheld by the Supreme Court in 1975 in United States v. Maine.<sup>18</sup>

Where the coastline is relatively straight and unbroken, this three-mile line is relatively easy to locate. Where the coastline is broken by inlets, bays, and islands, however, the boundary is more difficult to determine. For these coastlines the Submerged Lands Act is ambiguous in defining the baseline from which the three miles are measured, with the result that the Supreme Court has had to resolve a number of disputes between the U.S. and coastal

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<sup>16</sup>In its 1982 offshore sale Alabama allowed bids on quarter blocks for one of the twelve tracts offered; there is no consensus on whether partial block bidding will be permitted in the future.

<sup>17</sup>43 U.S.C. §§1301-1315.

<sup>18</sup>420 U.S. 515 (1975).

states over the last twenty-five years.<sup>19</sup> While a number of general rules for locating the baseline have been established by the Court, the application of these rules to the peculiar circumstances of individual coastlines continues to be a source of conflict, and Alaska, Alabama, and Mississippi are all currently in various stages of litigation with the U.S. over boundary location.

Even when all disputes over the construction of these rules are eventually resolved, one issue threatens to provide a source of continuing trouble. According to the concept of ambulatory boundaries, which the Supreme Court first adopted in 1965 in United States v. California<sup>20</sup> and has since applied in other submerged lands cases, the offshore federal/state boundary remains a fixed distance (three nautical miles on the East Coast) from the existing coastline. As the coastline changes, then, so does the offshore boundary. Several authors have pointed out that the concept of ambulatory boundaries is a sound one in international law, as a nation's territorial sea should retain the same width regardless of coastal erosion and accretion. The concept is a terrible one to use in establishing property rights, however, and creates uncertainty in the conferring of long-term leases and may lead to protracted litigation.<sup>21</sup>

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<sup>19</sup>The main ambiguity was in the meaning of the term "inland waters" as used to define the coastline in Section 2 of the Act. In 1965 the Supreme Court adopted for use the definition of the term found in the Convention on the Territorial Sea and the Contiguous Zone, an international treaty ratified by the U.S. a short time before. While the decision settled some disputes, it also had the effect of injecting new ambiguities found in the Convention, such as the use of the straight baselines method, the meaning of the term "historic bay," and other matters. Many of these the court has since ruled upon. For a fuller discussion of these controversies and the Supreme Court decisions, see: Richard G. Hildreth and Ralph W. Johnson, Ocean and Coastal Law (Englewood Cliffs, NJ: Prentice-Hall, 1983), 514 pp.; Thomas Suher and Keith Hennessee, State and Federal Jurisdictional Conflicts in the Regulation of United States Coastal Waters, Sea Grant Publication UNC-SG-74-05 (Raleigh, N.C.: University of North Carolina Sea Grant Program, 1974), 75 pp.; John L. Taylor, "The Settlement of Disputes Between Federal and State Governments Concerning Offshore Petroleum Resources: Accommodation or Adjudication?" Harvard Int. Law Journal 11:358-399, 1970.

<sup>20</sup>381 U.S. 139 (1965).

<sup>21</sup>Robert Kreuger, "The Background of the Continental Shelf and the Outer Continental Shelf Lands Act," Nat. Res. J. 10:463, 1970; Taylor, "Settlement of Disputes Between Federal and State Governments," pp. 368 ff. A bill was introduced recently in Congress to help remedy this situation. S. 1878, entitled the "Seabed Boundary Act" and introduced Sept. 22, 1983, by Senator Robert Dole, would establish a mechanism whereby a coastal state and the federal government could voluntarily agree to permanently immobilize the federal/state boundary. Whether states would avail themselves of such an opportunity is an open question. For North Carolina, where the coastline is generally receding and is expected to continue to do so, such an agreement would make sense. The risk in such an agreement is that a major change in direction by the Supreme Court could provide additional territory to states

The Minerals Management Service has undertaken a program to establish, at least temporarily, federal/state boundaries with a maximum degree of precision. The program is being undertaken by MMS's Cadastral Engineering Section in Denver and involves use of the best available data to select salient points along the baseline and a computer program to calculate boundary location with a precision not previously obtained. Charts showing these boundaries are sent to regional MMS offices and then individual states for review. The current schedule calls for the North Carolina coast to be done during FY 84, with charts sent to the MMS Atlantic OCS office by Sept. 1, 1984.<sup>22</sup> To protect the state's interest, the Department should carefully inspect these charts and the various rules and interpretations upon which they are based.

Fortunately North Carolina's tideland lateral boundaries with Virginia and South Carolina are a simpler matter. Both boundaries have been established by interstate compacts and are fixed precisely and in perpetuity. In each case the agreement was enacted by the legislatures of the two states concerned and ratified by the U.S. Congress.<sup>23</sup>

As for the upland boundaries of the state's submerged lands, N.C. Gen. Stat. §77-20, passed in 1979, formally declares the seaward boundary of private oceanfront property to be the mean high water mark, with the exception of lands below mean high water where title has been specifically granted by the state (see below). North Carolina has historically been a mean high water state, and its Supreme Court has held so since 1817.<sup>24</sup> While mean high water may be difficult to locate with great precision,<sup>25</sup> such precision is generally

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that were not signatories to such an agreement, but the chances of this appear remote.

<sup>22</sup>Lee Thormalen, Minerals Management Service, personal communications, July 22 and November 3, 1983. The charts also depict the so-called "8g" line, named after Section 8g of OCSLA, which provides for consultation with states regarding the leasing of OCS lands within three miles of the federal/state boundary that might contain hydrocarbon pools that straddle the boundary.

<sup>23</sup>These boundaries are described at N.C. Gen. Stat. §141-8 (Virginia) and §141-7.1 (South Carolina); the 1981 amendment to the South Carolina boundary merely changed the language to read identically to South Carolina's, and the physical boundary itself was not altered. Congressional ratification of these agreements may be found at 86 Stat. 1298 (Virginia) and 95 Stat. 988 (South Carolina).

<sup>24</sup>McKenzie v. Hulet, 4 N.C. 613 (1817). See Daniel F. McLawhorn, "Ownership of the Estuarine Lands in North Carolina: Has the Public Trust Been Sold?" mimeo, North Carolina Department of Justice, Raleigh, N.C., 32 pp.

<sup>25</sup>See Vann Irvin, "In Search of Mean High Tide," mimeo, Center for Urban and Regional Studies, The University of North Carolina at Chapel Hill, Chapel Hill, N.C., and Aaron L. Shalowitz, Shore and Sea Boundaries, 2 Vols. (Washington, D.C.: Coast and Geodetic Survey, U.S. Department of Commerce, 1962-64).

unnecessary for the purposes of oil and gas leasing. Upland boundaries are also ambulatory, however, and the same problems may arise as with the federal/state boundary discussed earlier.<sup>26</sup>

Interests in Submerged Lands. When conflicts arose over oyster cultivation rights in the early 1960's, the General Assembly enacted N.C. Gen. Stat. §113-205, which required anyone "claiming title to any part of the bed lying under navigable waters of any coastal county of North Carolina or any right of fishery in navigable waters of any coastal county superior to that of the general public" to register that claim with the state by Jan. 1, 1970.

Over 10,000 claims were eventually filed, some dating back to the colonial period. Many were claims of fee title based on North Carolina's entry and grant statutes and Board of Education deeds. Others were based on licenses, grants, and perpetual franchises for oyster cultivation issued under 19th century statutes, oyster leases granted in this century, and a variety of other interests. Certain interests in submerged lands continue to be granted by the state, including shellfish leases issued by the Marine Fisheries Commission and utility rights-of-way and easements for special water-dependent uses granted by the State Property Office.

While some of these claims, particularly those based on recent grants, are undoubtedly valid, many others are questionable. In some cases it appears that the claims are for greater interests in land than were actually granted by the state; in others, it is unclear exactly what interests were granted by the state, or whether the state even had the authority to make such grants. There is a dearth of relevant court cases on the subject, and the whole issue is a confused and difficult one. A state task force comprised of representatives from the Departments of Administration, Justice, and Natural Resources and Community Development is currently reviewing the claims and formulating policies to address the issue. This subject will not be dealt with further here; for more information on the subject, see the papers by Rice, Earnhardt, McLawhorn, and Marlow and Propst.<sup>27</sup>

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<sup>26</sup>A receding shoreline will generally favor the state at the expense of the upland owner, but the state will be the loser on the backside of the barrier islands if the islands continue their migration shoreward. Although there has been little case law concerning the effect of shoreline changes on mineral rights, one recent decision found the severed mineral estate to be subject to gain or loss as a result of erosion or accretion. Nilsen v. Tenneco Oil Co., (Okla. Sup. Ct.) 614 P.2d 36 (1980).

<sup>27</sup>David Rice, "Estuarine Land of North Carolina: Legal Aspect of Ownership, Use and Control," N.C. Law Rev. 46:779-812, 1968; Thomas W. Earnhardt, "Defining Navigable Waters and the Application of the Public Trust Doctrine in North Carolina: A History and Analysis," N.C. Law Rev. 49:888-920, 1971; McLawhorn, "Ownership of the Estuarine Lands in North Carolina;" Kim Marlow and Luther Propst, Annotated Bibliography: The Public Trust Doctrine in Submerged Lands in North Carolina (Raleigh, N.C.: UNC Sea Grant College Program, 1983), 15 pp.

If a private interest in a parcel of submerged land is established as valid, a series of questions presents itself with respect to the state's leasing of oil and gas rights:

(1) Did the state retain the parcel's mineral rights and the ability to lease them?

(2) If the state leases the oil and gas rights, must the oil and gas lessee obtain the consent of the surface owner/lessee to enter and use the surface for exploration and development?

(3) If the oil and gas lessee has the right to enter and use the surface, what is his liability for damages?

Unfortunately there are no simple answers to any of these questions. There is virtually no case law on these subjects in North Carolina. In other states there has been substantial litigation on some points but very little on others, and on those aspects that have been litigated, the rulings have sometimes been inconsistent. For a fuller discussion of these questions see Williams and Meyers, Hemingway, and Kuntz;<sup>28</sup> a brief summary of their conclusions on each of these questions is ventured below:

(1) Whether the state retained the mineral rights and the ability to develop (or lease) them will depend on the exact wording of the conveyance. In general, a fee conveyance carries with it the mineral estate while an easement or leasehold does not, but exceptions exist.<sup>29</sup>

(2) It is generally accepted that ownership of oil and gas rights carries with it, by implication, the means of enjoying the mineral estate. The owner of oil and gas rights "has the right to enter upon and make reasonable use of the surface in connection with exploring for and exploiting the mineral deposits."<sup>30</sup> A mineral owner is not liable for damages caused in the exercise of this right, though some courts have ruled that he is obligated to minimize such damages.

It is fairly clear that where surface easements or leaseholds are created after a mineral leasehold, since the right of the mineral lessee to reasonable use of the surface was granted (incident to the mineral lease) by the fee

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<sup>28</sup> Howard R. Williams and Charles J. Meyers, Oil and Gas Law, Volume 1 (New York: Matthew Bender, 1981 with 1982 suppl.); Richard Hemingway, The Law of Oil and Gas (St. Paul: West Publishing, 1971 with 1979 suppl.); Eugene Kuntz, A Treatise on the Law of Oil and Gas, Volume 1 (Cincinnati: W.H. Anderson, 1962 with 1983 suppl.).

<sup>29</sup>Hemingway, Law of Oil and Gas, p. 189.

<sup>30</sup>Kuntz, A Treatise on the Law of Oil and Gas, Vol. 1, p. 80. It should also be noted, however, that such a right is subservient to certain public rights, and that, regarding submerged lands, existing navigation and environmental laws may sharply reduce the area within a lease available for drilling operations.

owner before surface rights were granted to another party, the latter is subject to the former's use of the surface.<sup>31</sup>

Where the surface easement or lease precedes the mineral lease in time, however, the situation is more complicated. Some have argued successfully that the easement owner or surface lessee can forbid an oil and gas lessee's entry based on the covenant of quiet enjoyment that is usually implied in conveyances of easements and leases for years. Decisions in some cases have hinged on the exact wording of the surface lease, particularly whether the lease referred to sufficiently specific surface uses as to have effected a severance of the mineral estate.<sup>32</sup> Case law is not consistent on this point. Such conflicts are often avoided through the negotiation of a "Tenant's Consent Agreement" between the oil and gas lessee and surface tenant for payment of surface damages; the agreement subordinates the right of the prior tenant to the oil and gas lessee.<sup>33</sup>

(3) The liability of oil and gas lessees for surface damages has been a common subject of litigation. The general rule appears to be that where the oil and gas leasehold was created first, the surface tenant is entitled to compensation only when the oil and gas lessee's use of the surface becomes unreasonable or excessive.<sup>34</sup> Where the oil and gas lease is let after conveyance of a surface easement or leasehold, the owner of the surface interest may be entitled to compensation for all damages.<sup>35</sup> Many contemporary leases contain a "surface damage clause" that requires the oil and gas lessee to compensate the surface owner or tenant for all damages caused by oil and gas operations.<sup>36</sup> Care must be taken in constructing such clauses to ensure that all possible circumstances are covered. In North Carolina, for instance, easements have not been required for projects involving normal riparian access such as wharves, piers, and docks, and the interests of these owners should be protected as well. In Alaska state leases, the mineral lessee is required to make advance arrangements with the surface owner or tenant for payment of all damages caused by the mineral lessee's use of the surface.<sup>37</sup> If an agreement

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<sup>31</sup>Williams and Meyers, Oil and Gas Law, Vol. 1, §218.3

<sup>32</sup>*Ibid.*

<sup>33</sup>Hemingway, Law of Oil and Gas, p. 190.

<sup>34</sup>Decisions have fairly consistently held that under such circumstances, the surface lessee must prove negligence on the part of the oil and gas lessee to win damages. For examples involving oyster leases, see Vodopija v. Gulf Refining Co., 198 F.2d 344 (1952), and Trosclair v. Superior Oil Co., 219 So.2d 278 (La.) (1969).

<sup>35</sup>Kuntz, A Treatise on the Law of Oil and Gas, Vol. 1, p. 207, but exceptions exist; see, e.g., Jurisich v. Louisiana Southern Oil and Gas Co., 284 So.2d 173 (La. App.) (1973).

<sup>36</sup>Williams and Meyers, Oil and Gas Law, Vol. 1, §218.11.

<sup>37</sup>Alaska Stat. §38.05.130

between the parties cannot be reached, the mineral lessee may enter the surface after posting a bond deemed sufficient by the state.

It is apparent from these considerations that, when a tract is being considered for leasing, (a) all claims to interests in the tract should be investigated and, where conflicts exist, resolved if possible, (b) questions of access rights and liability should be researched and fully discussed for the benefit of all parties, and (c) appropriate lease provisions should be written into the oil and gas lease (and future shellfish leases?) to clarify the obligations of the parties involved and to help prevent litigation.

To protect against the possibility that a successful claim may be pressed against the state after an oil and gas lease has been sold, the current Mississippi lease contains the following provision: "This lease is granted and accepted without any warranty of title or accuracy of description, either express or implied, and without any recourse against Lessor for return of any payments, once made by Lessee." Several other states have similar clauses, and warnings to this effect are commonly published in the final notice of sale.

If a title dispute is identified before a lease sale, negotiation or litigation may be used to quiet title. Alaska and the federal government, for instance, have recently implemented a several-step process of fact-finding, negotiation, and if necessary, litigation for resolving their many outstanding title disputes. Occasionally both parties to a title dispute may be interested in seeing the land brought into production as soon as possible, in which case they may enter into agreements for the issuance and administration of leases, with the revenues deposited in an escrow account until the dispute is resolved. Alaska, California, and federal law all authorize the appropriate agencies to execute such agreements.<sup>38</sup> Primarily for this reason, Alaska and the U.S. held a joint lease sale for tracts in the Beaufort Sea in 1979.<sup>39</sup>

#### Checkerboard Leasing and Surrender Requirements

Some people have argued in favor of leasing schemes that generate information on unleased areas. The rationale behind such schemes is that by making more information available on unleased lands, uncertainty is reduced, and on average, the state realizes a higher return. Though sometimes more information will result in lower lease values, the net effect will tend to be positive, as the information will reduce risk and allow companies to reduce the risk premiums they must factor into their bids. Two options for generating information on unleased areas are checkerboard leasing and surrender requirements.

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<sup>38</sup>Alaska Stat. §38.05.137; Cal. Public Resources Code §6813; 43 U.S.C. §4732.

<sup>39</sup>Details of the joint sale are discussed in J.B. Jackson and F.N. Kurz, Arctic Summary Report, January 1983, prepared for the OCS Oil and Gas Information Program, Minerals Management Service (Reston, Va.: Rogers, Golden & Halpern, Inc., 1983), pp. 19-27.

Checkerboard leasing. With this approach every other tract is leased in an initial sale, and the remaining tracts are leased as information accumulates from exploration of the initial tracts.<sup>40</sup> The major advantage of this approach is that if a commercial find is made, the government realizes the dramatic rise in value of adjacent tracts. Such a scheme avoids the situation in which an entire productive structure is leased initially at low terms.

Unfortunately there are several disadvantages to checkerboard leasing. The lessees of initial tracts must be required to release their exploration results before the sale of adjacent tracts, something they will be reluctant to do and which may cause them to lower their bids on the initial tracts. If the time between sales of adjacent tracts is long, field development will be more difficult and costly. There is also a risk to the initial bidders that the government may never lease the adjacent tracts, thereby increasing the size of a find needed to make any discovery commercial and probably also resulting in lower initial bids. Finally, in high-cost, high-risk frontier areas, it may be necessary to offer an entire structure as incentive before industry will be willing to bid.

Alberta has experimented with checkerboard leasing, and Canada uses a variant of it offshore.<sup>41</sup> California considered a checkerboard pattern for the Point Conception sale, but concluded that it was not consistent with the state's policy of encouraging consolidation of facilities and operations.<sup>42</sup> No other states use checkerboard leasing.

Surrender requirements. This approach entails use of large exploration leases with smaller development selection rights. The lessee is initially granted an extensive lease area, but after a certain period of time or when a discovery is made, the lessee must select a portion of the tract to hold for development and is required to surrender the rest. All of North Carolina's previous leases were of this type, and both Canada and Britain require licensees to surrender at least 50% of each lease tract.<sup>43</sup> On the other hand, none of the principal leasing programs in the U.S. include surrender requirements.

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<sup>40</sup>Hayne E. Leland and Richard B. Norgaard, "An Economic Analysis of Alternative Outer Continental Shelf Petroleum Leasing Policies," paper prepared for the Office of Energy R and D Policy, National Science Foundation, 1974, 79 pp. (NTIS No. PB 285 823). Checkerboard leasing is discussed on pp. 65-66.

<sup>41</sup>Ibid., p. 65; Michael Crommelin, "Offshore Oil and Gas Rights: A Comparative Study," Natural Resources Journal 14:475-6, 1974.

<sup>42</sup>California State Lands Commission, "Staff Report on Current Status of Proposed Pt. Conception/Pt. Arguello Oil and Gas Leasing Program," Nov. 29, 1982, mimeo, p. 25.

<sup>43</sup>Crommelin, "Offshore Oil and Gas Rights," pp. 475-6; Kenneth W. Dam, Oil Resources: Who Gets What How? (Chicago: Univ. of Chicago Press, 1976), pp. 49-51.

The advantages of surrender requirements are similar to those of checkerboard leasing: less uncertainty and risk leading to higher government revenues, and better information for government decision-makers. In this case the exploratory data will be for land surrendered and available for leasing, rather than simply adjacent blocks. However, surrender requirements also have a number of disadvantages:

- (a) exploration results must be made public;
- (b) the larger size of exploration tracts may prevent small firms from competing, thereby reducing competition and government revenues;
- (c) the strategy of lessees will be to determine as efficiently as possible which tract(s) to select for development, and the rest of the exploration lease area may be explored only superficially;
- (d) the initial lessee bears the risk that the development parcel selected will have insufficient production potential to justify development and that the government will not lease adjacent areas for many years (which risk will tend to reduce bids); and
- (e) the government must consider the environmental and socio-economic impacts of development that might occur anywhere within the exploratory area, a far more difficult task than evaluating several small blocks.<sup>44</sup>

Because of the problems created by checkerboard leasing and surrender requirements, it is recommended that the state not adopt either as standard practice. However, it is conceivable that either approach could be used flexibly to enhance the government's prospects in particular sales. While a rigid checkerboard pattern may not be preferable, neither is the offering of large groups of contiguous blocks, and a middle ground in which small groups of blocks are offered may be desirable. Large exploration leases should not be offered, for reasons described earlier in this section, but surrender provisions may have a place in small leases. For instance, where four blocks cover a promising structure, the state might offer all four blocks under one lease but with a requirement that two of the blocks be surrendered later. This would provide companies with a little more incentive than if just two blocks were offered, since the lessee would at least have the option of selecting the more productive blocks.

#### Coordination of Sales with Adjacent Owners

Should lease sales be coordinated with those of adjacent owners? Since the owner sharing the longest common boundary with North Carolina is the federal government, this question is primarily concerned with OCS sales. There are several factors to consider. If the state leases acreage adjacent to the boundary at the same time as the federal government, industry planning and exploration expenditures will be reduced and any field lying across the boundary can be developed efficiently as a unit. By leasing state lands

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<sup>44</sup>Many of these are drawn from Leland and Norgaard, "Outer Continental Shelf Petroleum Leasing Policies," pp. 64-65.

adjacent to federal leases the state can also avoid significant drainage across the boundary, though the Outer Continental Shelf Lands Act contains a provision to adequately compensate the state should this occur.<sup>45</sup>

With respect to the relative timing of the state and federal sales, there are arguments to support several different options. If the state sale is held before the federal one, all of the potential OCS bidders with their assembled bonus moneys are available to participate, but they may hold back if the more attractive prospects are on the OCS. If the state sale is held shortly after the federal one, the state can take advantage of all the losing bidders who now have large sums of bonus cash available and perhaps hopes of acquiring more leases in the area. Which tactic is best probably depends on which jurisdiction contains the best prospects, as companies will tend to harbor their resources for bidding on these tracts. The state could also schedule the sale of adjacent tracts 2-3 years after the federal sale, so as to take advantage of the exploration results of the OCS lessees.

Both Alaska and Texas have made attempts to coordinate their programs with the federal government. In both cases BLM/MMS has shown no interest in reciprocating.

Coordination with an OCS sale may occasionally make sense, and in these cases the state should give special consideration to applications for offerings of adjacent tracts. Where state oil and gas resources are threatened elsewhere by drainage, i.e., along the state's upland and lateral borders, special consideration should also be given to leasing.

#### The Rate of Leasing

What is an appropriate rate of leasing? How quickly should eligible areas be offered for lease? In addition to the previous two topics, both of which involve elements of rate, there are several other relevant considerations:

Government revenues. In The Leasing of Federal Lands for Fossil Fuels Production, McDonald argues that the primary objective of government leasing strategy should be for the government to capture a maximum of the present value of the pure economic rent arising from minerals production on public lands, where pure economic rent is the income which tends to accrue in the long run, under conditions of perfect competition and the absence of

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<sup>45</sup>OCSLA §8(g), 43 U.S.C. §1337(g). Subsection (4) requires that federal revenues from pools underlying the OCS/state boundary be placed in escrow until an agreement is reached on "the fair and equitable disposition of such revenues." A recent district court decision in Texas held that Texas was entitled not only to the value of the hydrocarbons drained by federal lessees from state lands, but also to a portion of the increase in value of federal tracts resulting from leasing and exploration in state waters. If upheld on appeal, the decision will give states more incentive to lease tracts adjacent to the OCS. Wall Street Journal, Feb. 21, 1984, p. 8.

externalities, to owners of raw natural resources.<sup>46</sup> With regards to the rate of leasing, such an approach leads him to the conclusion that rapid leasing will tend to maximize the present value of the income received, though this trend must be tempered by the possibility that accelerated leasing will, in the short run, overwhelm the abilities of companies to explore and develop lease tracts and will therefore depress rents.<sup>47</sup> However, McDonald's focus is on the federal program, where approximately one billion acres are available on the OCS. In North Carolina, where submerged lands total approximately two million acres, it is unlikely that any decisions on leasing rates will have any serious effect on the U.S. oil and gas industry as a whole, though they might on the small segment of the industry willing to undertake the risks of exploring in North Carolina.

Leland and Norgaard make several arguments for an active government role in the rate decision and the spreading out of leasing over time.<sup>48</sup> These are based on (1) differences in the discount rates used by government and industry, resulting in suboptimal investment and faster than optimal production; (2) opposing reactions to risk between government and industry, also resulting in faster than optimal production; (3) possible problems with industry instability (a tendency for boom-bust cycles); and (4) possibilities for improving the generation of geological information and thereby reducing the risk for both government and industry. This last point was partially addressed in the discussion of checkerboarding and surrender requirements earlier in this chapter; other options include contract exploration and exploration tax credits. With regards to boom/bust cycles, while North Carolina is in no position as a resource owner to influence these cycles (as Leland and Norgaard suggest the federal government may be), the state should certainly be sensitive to them in timing its sales to maximize revenues. The dramatic change in market conditions for oil and gas rights between 1981 and 1982 is an excellent example.<sup>49</sup>

Finally, any expectation of an increase in net revenues from a unit of production (oil value minus costs) may make leasing delays preferable if the private discount rate is greater than the social rate, as is likely.

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<sup>46</sup>Stephen L. McDonald, The Leasing of Federal Lands for Fossil Fuels Production (Baltimore: The Johns Hopkins Univ. Press for Resources for the Future, 1979), p. 2.

<sup>47</sup>*Ibid.*, pp. 81-91.

<sup>48</sup>Leland and Norgaard, "Outer Continental Shelf Petroleum Leasing Policies," pp. 52-58.

<sup>49</sup>Illustrative of this change are the results of OCS Sales 56 and RS-2 (in August 1981, and August 1982, respectively). Two tracts were bid on in both sales. The high bids were, for tract 27: \$3.324 million (Sale 56), \$1.713 million (RS-2); for tract 97: \$746,000 (56), \$150,000 (RS-2). In each case the Sale 56 bids were rejected as insufficient, and the RS-2 bids were accepted. No exploratory drilling took place in the region between the two dates, and probably little, if any, geophysical exploration.

Economies of scale. Rapid leasing permits certain economies of scale, in exploration, development, and production, that a slower pace of leasing may not allow. To the extent that these can be foreseen by companies prior to leasing, a slow pace may depress rents; to the extent they cannot, slow leasing will reduce company revenues. If all of the tracts overlying a marginal field are not under lease at the same time, development may even be precluded. Economies of scale may also produce economies in the amount of disturbance. Where many blocks in an area are leased together, fewer facilities may be needed to explore and develop the area than if the blocks were leased a few at a time over a period of many years.

Administration of the leasing program. The rate of lease offerings should be such as to not overload the state bureaucracy charged with reviewing lease proposals and overseeing active leases. This will be particularly crucial early in the program when the bureaucracy is inexperienced and program procedures are still being refined. There should be an opportunity for the bureaucracy to learn from its mistakes before large areas are leased and committed to development.

Assimilative capacity of the natural and socioeconomic environments. In determining the rate at which lands will be leased the state needs to consider the assimilative capacity of the natural and socioeconomic environments for leasing-induced change. Environmental impacts that are cumulative over space but are temporary or diminish with time are important factors in the rate decision. The pace of leasing should also allow for a gradual and sustained build-up of ancillary industries, where possible, and for adequate planning to minimize social and economic disruption in coastal communities.

## 5.5 Pre-Sale Exploration

In order to prepare bids, companies must acquire information on the oil and gas potential of the area in question. Two groups of exploration methods are typically used: geophysical methods (such as magnetic, gravity, and seismic surveys) and geological methods (bottom sampling and shallow drilling or coring).<sup>50</sup> The conduct and interpretation of seismic surveys account for

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<sup>50</sup>Another method of pre-sale exploration is the deep stratigraphic test well. These wells are drilled into the area of interest but usually away from any potentially oil-and-gas bearing structure. They are drilled primarily for geologic and engineering data which are used to evaluate the area's petroleum potential and possible drilling problems, and are usually not completed even if commercial quantities of oil or gas are found. As offshore wells are very costly, companies usually fund the drilling collectively. Wells on the OCS are known as Continental Offshore Stratigraphic Test (COST) Wells, and extensive rules governing their drilling may be found at 30 CFR 251. Alaska's rules at 11 AAC 96 are considerably simpler. It is unlikely that any deep stratigraphic test wells would be drilled in North Carolina waters, as the type of geological information obtained from these wells is available for the most part from the many other wells already drilled in the coastal plain (Figure 4-1). Should any companies be interested, they would undoubtedly come to the

approximately 90 percent of exploration dollars.<sup>51</sup>

Seismic data may be obtained in several ways. Some of the larger oil and gas companies are equipped to conduct their own seismic work. More often a company will hire a firm that specializes in seismic exploration, and when several companies are interested in an area, they may band together to fund a "group shoot." Sometimes a seismic firm will conduct surveys on a speculative basis without a contract, hoping to sell the data later.

In the public waters of many states and on the OCS, a permit is required to conduct exploration activities. The rationale for regulating such activities is that: (1) these activities may have adverse impacts on the natural environment and may conflict with other uses of the area, particularly commercial fishing; (2) permitting is necessary to ensure access to the data later by the public agency; and (3) in some cases, government involvement may facilitate information acquisition and cost sharing among companies (e.g., MMS regulations on deep stratigraphic test drilling). The degree of regulation in different programs is shown in Table 5-9.

NRCD has promulgated regulations on this subject under authority of the Oil and Gas Conservation Act.<sup>52</sup> The rules require a permit for all seismic work involving the use of explosives (powder, dynamite, nitroglycerin, etc.). Every crew conducting seismic activities must be accompanied by a seismic agent, a state employee who observes the operation and has authority to halt any shooting in violation of the rules. Restrictions on the size and use of explosives and the general conduct of operations are specified. A surety bond and evidence of insurance must be provided, and there are certain reporting requirements.

With respect to a submerged lands leasing program, these regulations are deficient in two principal regards:<sup>53</sup>

1) Permits are required only for seismic surveys using explosives. Other methods, including seismic surveys using air guns or sparkers, other geophysical methods, and geological methods, are not covered (although the latter, which involve bottom disturbance, probably require permits under CAMA). Such lack of regulation is appropriate for exploration on private lands, where the state's concern is in preventing harm to neighboring properties and public resources. In public waters and marsh areas, however, other exploration methods should be regulated as well, for several reasons. First, non-explosive methods may have undesirable impacts. In several areas of the

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state to request that the Conservation Act regulations guaranteeing well record confidentiality for only 1-2 years (15 NCAC 5D .0008, .0010) be changed; this would give the state time to review the situation and to evaluate its regulatory authority under the Conservation Act and CAMA.

<sup>51</sup>Petroleum Extension Service, A Primer of Offshore Operations (Austin, TX: Petroleum Extension Service, University of Texas at Austin, 1976).

<sup>52</sup>15 NCAC 5C.

<sup>53</sup>The study did not attempt a technical assessment of these regulations.

Table 5-9

Regulation of Petroleum Exploration by Selected States  
and the Federal Government

<u>Program</u>	<u>Permit required for petroleum exploration in submerged lands using:</u>			<u>Must results be submitted upon request?</u>
	<u>Seismic Methods</u>	<u>Other Geophysical Methods</u>	<u>Geological Sampling</u>	
Alabama	X	X	X	
Alaska	X			X
California	X	X	X	X
Louisiana	X			
Mississippi	X	*	*	X
Texas	X	X	X	X
U.S. OCS	X	X	X	X
North Carolina	X**			

\*Authorized by law to require permit for this activity, but no permit currently required.

\*\*Seismic methods involving the use of explosives only.

country, conflicts between seismic firms and commercial fishermen have arisen over interference between vessels and the possibility that seismic boomers may harm fish larvae. These conflicts have reached a heated pitch in California. Second, the state should simply be aware of who is evaluating public resources. Finally, permits are necessary if the state is to require that survey results be available for state use (see below).

2) The regulations do not require that survey results be made available to the state. Current rules read that "the department on request will have access to all records, . . . but only to the extent necessary to determine

that all protective requirements have been complied with."<sup>54</sup> The rationale for expanding this requirement is that the state needs access to survey data so that it can estimate the potential of each tract in order both to evaluate whether bids are adequate and to weigh the petroleum potential against the risks of development.

Five of the seven programs examined require that survey results be made available to the permitting agency (Table 5-9). Texas rarely exercises its option to acquire this information, as the General Land Office does not have the manpower to interpret it; the state instead relies primarily on competition to ensure receipt of fair market value.<sup>55</sup> On the other hand, before the recent sale in Mississippi and the scheduled sale in California, neither program had the authority to require disclosure of exploration results. Their experiences with these sales convinced both states of the importance of such disclosure, and both legislatures have recently enacted laws authorizing the appropriate agencies to require disclosure of survey results.<sup>56</sup>

As the data may be bulky and expensive to reproduce, these regulations only require disclosure upon request, and the permitting agency is responsible for copying costs. It is important that such regulations require disclosure not only of raw data, but also of results of any processing, analysis, and interpretation.<sup>57</sup>

It is essential that disclosed exploration data be kept confidential, or much of the incentive to explore will be lost. Under current North Carolina law, however, the state is bound to release such information when requested to do so. Chapter 132 of the General Statutes declares that all public records, the definition of which would include disclosed exploration results, may be

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<sup>54</sup>15 NCAC 5C .0021(b).

<sup>55</sup>Of the two states that are not authorized to require disclosure, Alabama relied on competition to generate bids of fair market value in its 1981 sale, while Louisiana uses comparable values and geologic information from nearby wells to evaluate tract potential.

<sup>56</sup>For those particular sales, the two states approached their lack of geological data very differently. Mississippi went into the sale "blind" and relied on competition to assure receipt of fair market value. California, partly out of need for information and partly in the belief that government exploration is more efficient from a societal viewpoint, contracted for seismic data and interpretation at a cost of \$340,000. At one point the State Lands Commission also contemplated an exploratory drilling program before the sale whose cost would have run into the tens of millions of dollars, but later abandoned the idea. Of course, California already knew from adjacent OCS sales that the tracts in question had very high resource potential, something Mississippi did not.

<sup>57</sup>Examples of disclosure regulations may be found at 30 CFR 251.11-.14 (U.S.) and 11 AAC 96.210-.240 (Alaska).

"inspected and examined at reasonable times . . . by any person. . . ." A statutory exception will be needed to overcome this difficulty.<sup>58</sup>

Even where the government agrees to maintain results as confidential, though, industry has objected strenuously to disclosure requirements. Employees of government agencies and contractors may leak the results, or results may be disclosed as employees change firms. Where companies perceive that disclosure requirements increase the risk of leaks, such requirements will create a disincentive to expensive exploration programs. Provisions that attempt to counter these problems have been adopted by some or all of the programs involved, and include:

(a) All such information is held confidential for a certain length of time (10 years is typical), and the state agrees to be liable for any unauthorized use;

(b) The state may disclose the information to a third party (typically a firm hired to process or analyze the data further), but the third party must agree in writing not to disclose the information to anyone and not to acquire an interest in the land in question. The contractor is held liable for unauthorized use and may be required to post bond, and the original permittee may be given a chance to comment on the disclosure before the transfer occurs.

(c) The individual responsible for any unauthorized disclosure may be not only liable for civil damages but also subject to criminal charges.

Should North Carolina adopt disclosure requirements (and they are recommended), such requirements should be accompanied by stringent procedures and penalties to prevent unauthorized use.

However, it appears that NRCO does not currently have the authority to require such disclosure. There is nothing in the Oil and Gas Conservation Act to indicate that disclosure of survey results would further the purposes of the law. The state, therefore, has two options. The General Assembly could pass legislation authorizing NRCO to require disclosure.<sup>59</sup> This would be the

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<sup>58</sup>Precedent for such an exception exists regarding disclosure of business data by seafood licensees. N.C.G.S. §113-163(c).

<sup>59</sup>Examples of legislative authority for disclosure are Miss. Code Ann. §29-7-3, Cal. Public Resources Code §6826, and 43 U.S.C. §1352(a). Comparable legislation for North Carolina might look something like this:

(a) Any lessee or permittee conducting any exploration for, or development or production of, oil or gas on state-owned lands, including tide and submerged lands, shall, upon request, disclose to the Secretary of the Department of Natural Resources and Community Development all data and information (including processed, analyzed, and interpreted information) obtained from such activity.

(b) Such data and information shall not be considered public records within the meaning of Chapter 132 of the General Statutes. The Secretary shall promulgate regulations prescribing the time periods and conditions which shall be applicable to the release of such information.

simplest and most straightforward approach and is recommended. The law could provide clear authority for the regulation of all exploratory activities as well (see #1 above), which authority is somewhat tenuous under the Oil and Gas Conservation Act.<sup>60</sup> A second option would be to require the submittal of all geological and geophysical information in order to qualify for bidding. This would avoid the necessity of going to the General Assembly, but is unsatisfactory on two counts. Data would arrive within days of the sale, forcing the state either to delay announcement of lease awards for weeks while the data are studied, or to not use the data. The state would also lose the data of firms that explored but decided not to participate in the sale.

#### 5.6 Selection of Lessee

This subchapter will examine how a competitive bidding or auction system might be constructed for a submerged lands leasing program. It is proposed that such a system be designed to promote several objectives. They are, first and foremost,

- to capture a major portion of the economic rent accruing from oil and gas rights for the government (or, at least, to realize fair market value);

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(c) Whenever any employee of the State of North Carolina reveals information in violation of the regulations promulgated pursuant to subsection (b) of this section, the lessee or permittee who supplied this information to the Secretary, and any person to whom such lessee or permittee has sold such information under promise of confidentiality, may commence a civil action for damages in a court of competent jurisdiction against the State of North Carolina. The State will not raise as a defense any claim of sovereign immunity or any claim that the employee who revealed the privileged information which is the basis of the suit was acting outside the scope of his employment in revealing such information.

(d) Any person who makes unauthorized disclosure of such data and information shall be guilty of a misdemeanor, and upon conviction be fined not more than five thousand dollars (\$5,000.00) or imprisoned not more than one (1) year, or both.

<sup>60</sup>A separate section to provide this authority might read like this: After Jan. 1, 1986, no person shall conduct any geological or geophysical exploration for mineral resources (including, but not limited to, gravity, magnetic, and seismic methods, core and test drilling, and various bottom sampling techniques) in state-owned tide and submerged lands without having first obtained a permit from the Department of Natural Resources and Community Development. Such permit shall be issued only if the Secretary or his designated representative determines that in accordance with rules issued by the Secretary, (1) the exploration will not interfere with or endanger operations under any lease issued pursuant to N.C. Gen. Stat. §146-8; and (2) such exploration will not be unduly harmful to aquatic life, result in pollution, create hazardous or unsafe conditions, unreasonably interfere with other uses of the area, or disturb any site, structure, or object of historical or archeological significance.

and secondarily,

- to transfer these rights to the most efficient firm, thereby minimizing social costs;
- to promote competition and the entrance of relatively small firms into the market;
- to minimize administrative costs;
- to promote a socially optimal rate of exploration, development, and production; and
- to maintain the confidence of industry and the public with selection criteria that are clearly written and fairly applied.<sup>61</sup>

#### Competition and Uncertainty

Studies and experience have shown that an auction system generally works best in realizing the above objectives when two considerations are present: a high degree of competition and a high degree of certainty regarding the value of the item for sale.

Competition. A high degree of competition is thought to have two beneficial effects: it increases the overall efficiency of the industry in exploring for and developing new sources of oil and gas, and it results in higher government

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<sup>61</sup>For comparison, in the conference report on the Outer Continental Shelf Lands Act Amendments of 1978 the House and Senate conferees declared it to be their intention that in utilizing the new bidding alternatives a variety of considerations should be taken into account, including, but not limited to: (i) providing a fair return to the Federal Government; (ii) increasing competition; (iii) assuring competent and safe operations; (iv) avoiding undue speculation; (v) avoiding unnecessary delays in exploration, development, and production; (vi) discovering and recovering oil and gas; (vii) developing new oil and gas resources in an efficient and timely manner; and (viii) limiting administrative burdens on government and industry. (U.S. House of Representatives, Conference Report on Outer Continental Shelf Lands Act Amendments of 1978, H. Rpt. 95-1474, 95th Cong., 2d session, 1978, p. 92.)

We have assumed receipt of fair market value to be one of the prime objectives of the leasing program and have designed the program accordingly. The state may very legitimately decide, however, that the recruitment of an offshore oil and gas industry and an exploration program that is more rapid and thorough than is likely to occur under existing market conditions are more important objectives. The state may therefore wish to sacrifice some of the fair market return to provide economic incentives for exploration and development, particularly in the early days of the program when the financial risk is very high. Such incentives can be provided in many ways, through public funding of exploration, exploration tax incentives, public/private joint ventures, or generous lease terms (including little or no royalty on an initial amount of production, a longer primary term, etc.). An incentive program need not include relaxed environmental protection.

revenues, based on the common assumption that greater competition causes individual firms to bid more aggressively.<sup>62</sup> How competitive is the bidding for North Carolina leases likely to be? The question should be divided into

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<sup>62</sup>This theory has an interesting wrinkle, commonly known as "the winner's curse," that is particularly applicable to oil and gas lease sales. It can be explained best by example. For a given sale, let us suppose that a company bids what it expects each tract is worth, based on its interpretations of exploration data and other information. For any given tract, we know that the company's bid will be either too high or too low, for uncertainties virtually ensure that a company cannot correctly estimate a tract's exact worth. But let us also suppose that, on average, the company's estimates are correct. Let us further suppose that other companies behave similarly. The result will be that during a sale company A will be more likely to win tracts whose worth it has overestimated, and less likely to win tracts whose worth it has underestimated. Thus even though its estimates are correct on average, the company wins a biased set of tracts that are apt to turn out to be poor investments. This is known as the "winner's curse." The mere act of winning diminishes the win's value. Notice also that as competition increases, the company will win fewer tracts, but the tracts it does win are apt to be those whose worth it has most overestimated, for on average one misjudges the true value of an item much worse when one comes out high against 50 other bidders than against only 2 or 3. Capen, Clapp and Campbell have argued that in order to ensure, on average, a specific rate of return under these circumstances, the appropriate response to increased competition is to bid less. (E.C. Capen, R.V. Clapp, and W.M. Campbell, "Competitive Bidding in High-Risk Situation," J. Petroleum Tech. 23: 641-653, 1971.) Put another way, greater competition diminishes the perceived value of winning because the mere act of outbidding a large number of rivals strongly suggests that the firm has been unduly optimistic. Any bid tendered, therefore, should reflect a company's perceived value of a tract assuming it already knows that no other competitors were prepared to bid higher. (James L. Smith, "Non-Aggressive Bidding Behavior and the 'Winner's Curse,'" Econ. Inquiry 19:380-388, 1981.) Capen et al. suggest that it is the winner's curse and the industry's failure to understand it that are responsible for the industry's historically low rates of return on offshore ventures in the Gulf.

How significant is the winner's curse in determining a firm's bidding behavior, and what does this portend for attempts to increase competition at lease sales? Smith used regression models to determine the factors controlling bid size in seven lease sales between 1974 and 1976. (James L. Smith, "Risk Aversion and Bidding Behavior for Offshore Petroleum Leases," J. Industrial Econ. 30:251-269, 1982.) He found a clear, positive correlation between competition and bid size, after controlling for a tract's estimated worth. This may indicate, as Capen et al. suggest, that bidders have been misinformed about their optimal bidding strategy, but with twenty years of industry bidding experience in offshore sales there is a strong presumption to the contrary. Smith's conclusion is that the typical response to increased competition is not so extreme as to produce non-aggressive behavior. Gilley and Karels point out that even if the optimal bid of a firm decreases as competition increases, that does not imply that government revenues will decrease, as there are more bids for the tract. (Otis W. Gilley and Gordon V. Karels, "The Competitive Effect in Bonus Bidding: New Evidence," Bell J. Econ. 12:637-648, 1981.)

two parts. First, how competitive is the offshore oil industry in general? Jones, Mead, and Sorenson researched this question and concluded that it is competitive and that a condition of free entry into the crude oil and gas production industry prevails in the U.S.<sup>63</sup> Their conclusion was based largely on two findings: (1) that the internal rates of return before taxes from offshore federal leases in the Gulf purchased between 1954 and 1962 was estimated to average 9.5 percent, considerably below the performance of the economy as a whole and hardly indicative of oligopolistic behavior,<sup>64</sup> and (2) that the concentration ratios for the industry, while substantial, were still below those considered typical of oligopoly. As drilling in nearshore waters is generally cheaper than on the OCS, it is likely that competition for nearshore tracts (as in North Carolina) would be even keener. Secondly, how competitive is North Carolina bidding apt to be? Prospects for oil and gas in this state must presently be considered poor. Not surprisingly, the experience in offshore sales has been that competition has been weakest for the least promising tracts. Tracts receiving only one bid are common; they constituted 54 percent of the OCS tracts that were bid on in 1982.<sup>65</sup> While there are a number of factors that determine the level of competition, it must be anticipated that, other things being equal, competition for North Carolina tracts will be low.

The state should therefore consider what steps it can take to enhance competition. There are two major ones:

- 1) Advertise the lease sale. This should be done in a timely manner so that firms have a realistic amount of time to undertake exploration and prepare a bid.

- 2) Minimize entry barriers to firms. Entry barriers can be either explicit or implicit. Explicit barriers can include eligibility criteria for bidding (see below), rules on the acceptability of joint bids,<sup>66</sup> and rules that disqualify bidders for immaterial mistakes in paperwork. Implicit barriers generally bar entry to relatively small firms and are due to the high

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<sup>63</sup>Russell O. Jones, Walter J. Mead, and Philip E. Sorenson, "The Outer Continental Shelf Lands Act Amendments of 1978," Nat. Res. J. 19: 885-908, 1979.

<sup>64</sup>In 1980, Mead and Sorenson extended their analysis to include leases issued through 1969. The aggregate rate of return for this larger group of tracts was estimated at 11.4% before taxes, up significantly from their earlier estimate on the older tracts, but still low relative to other business earnings. (Walter J. Mead and Philip E. Sorenson, "Competition and Performance in OCS Oil and Gas Lease Sales and Lease Development, 1954-1969," Reston, Va., 1980, as cited in Minerals Management Service, "Report to Congress on Fiscal Year 1982 Outer Continental Shelf Lease Sales and Evaluation of Alternative Bidding Systems" (n.p., 1983), 59 pp.)

<sup>65</sup>Minerals Management Service, "Report to Congress," p. 54.

<sup>66</sup>The question of restricting the formation of joint ventures is a controversial issue in offshore leasing policy. On the one hand, joint ventures are comparable to temporary mergers and may have similar anti-

capital requirements and high risks that offshore development entails.<sup>67</sup> Most firms can easily acquire capital once a discovery is made, but large amounts are often needed before a discovery for pre- and post-sale exploration and for

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competitive effects. This is of particular concern in an industry already suspected of oligopoly. (See Walter J. Mead, "The Competitive Significance of Joint Ventures," Antitrust Bull. Fall 1967, 819-849.) Concern that joint ventures among the majors would lead to reduced competition and an increase in their already sizable market share led the Department of Interior in September 1975 to ban joint bidding among firms that individually produce, on average during a six-month period, more than 1.6 million barrels or barrel-equivalents per day of crude oil, natural gas, and natural gas liquids. Congress enacted the ban into law three months later in the Energy Policy and Conservation Act (42 U.S.C. 6213(c); regulations now at 30 CFR 256.8-.44 and 10 CFR 376.301-.303). The firms on the most recent list of restricted joint bidders were Chevron, Exxon, Mobil, Texaco, and Shell (48 Fed. Reg. 45318, Oct. 4, 1983). The Justice Department also takes an active role in reviewing sale results for their anti-competitive consequences and has, on occasion, proscribed further ventures among firms not already on the list.

The Department of Interior has not conducted any empirical analyses to evaluate the joint bidding ban. Several economists have doubted its value, and no states have followed the federal lead. (See, for instance, Brian Sullivan and Paul Kobrin, "The Joint Bidding Ban: Pro- and Anti-Competitive Theories of Joint Bidding in OCS Lease Sales," Research Paper #010, American Petroleum Institute, Washington, D.C., 1978, 55 pp., and the unpublished Spann and Erickson study reported in McDonald, The Leasing of Federal Lands for Fossil Fuels Production, pp. 106-107.) There is, however, widespread agreement that joint bidding has a positive effect on competition with regards to other firms. Joint ventures allow these companies to compete with the majors for the more attractive prospects by sharing costs and risk. Greater competition, in turn, results in higher government revenues. Dougherty and Lorenz examined OCS lease sales between 1954 and 1974 and found that joint bidders tended to bid on the more sought-after (and apparently more valuable) tracts and tended to bid higher, on average, than their solo-bidding competitors. (E.L. Dougherty and J. Lorenz, "Statistical Analyses of Bids for Federal Offshore Leases," J. Petroleum Tech. 28:1377-1388, 1976.) In addition Smith's regression models of OCS sale results suggest that joint bids tend to be greater in magnitude than those that would be tendered by individual consortium members, though he noted that this might not apply to the seven major firms, who appear to have reached a position of risk neutrality. (Smith, "Risk Aversion and Bidding Behavior for Offshore Petroleum Leases.")

<sup>67</sup>The basic rationale in lowering such barriers is that where costs and risks are high only a few firms can afford to bid, and this lower level of competition results in lower government revenues and more opportunity for manipulation of the auction. While lower barriers will hopefully improve market performance, they should not be lowered so much that firms without the financial capability to meet the lessee's environmental, safety, and other responsibilities become competitive. In other words, while it may be laudable from a free-market and revenue standpoint to structure the auction so that small firms can compete with the big guys, there is a limit to how small a firm the state will want drilling for oil in its submerged lands.

payments to government, primarily bonuses.<sup>68</sup> These capital requirements may be lowered:

- (a) by tailoring the size of at least some tracts to the potential of the area, so that bonus bids will not be excessively high. Alaska tries to offer tracts in a range of sizes from one to nine square miles, so as to encourage participation by smaller firms.
- (b) by using bidding systems with low front-end payments. Bonuses can be spread out over time,<sup>69</sup> or emphasis shifted to royalties and profit sharing where payments are contingent on discoveries.

The traditional hypothesis of decreasing absolute risk aversion states that the premium required to induce a firm to accept a specific risk is inversely related to the size of the firm.<sup>70</sup> Therefore the larger the risk, the less likely that small firms will be competitive with larger ones. Smith found evidence of this in OCS bidding, where, after (hopefully) controlling for tract value and the degree of competition, he found that large firms tended to bid more than smaller ones, which he felt was best explained in terms of differing responses to risk.<sup>71</sup> There are two ways in which the state can reduce the risk for individual firms and thereby improve competition: by lowering the risk associated with individual tracts (discussed below under Uncertainty), and by permitting and encouraging diversification of risk. The latter may be accomplished by using bidding systems that transfer some of the risk to the government (substantial royalty and profit share rates make a substantial portion of compensation contingent on discovery of oil or gas), and by allowing the formation of joint ventures.

Uncertainty. If private firms are generally risk averse, then the higher the risk or uncertainty associated with an individual tract, the greater the risk premium will be. High risks therefore result in lower bids and lower government revenues.

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<sup>68</sup>In their study of Gulf tracts leased between 1954 and 1969, Mead and Sorenson found that leases attracting the highest bids tended to be the most productive, but that companies bid this productivity away so that the rate of return on these tracts was less, on average, than tracts purchased with smaller bonuses. This suggests that during this period high bonuses did not affect competition in a way that reduced government revenues. (Mead and Sorenson, "Competition and Performance in OCS Oil and Gas Lease Sales.")

<sup>69</sup>The Outer Continental Shelf Lands Act authorizes Interior to defer bonus payments up to five years (43 U.S.C. §1337(a)(2)). Logue, Sweeney and Willett suggest even easier terms for some leases: a payment schedule that does not require any payment for up to five years, and payment after that in annual installments over a 10-20 year period, guaranteed by a bond or insurance. (Dennis E. Logue, Richard J. Sweeney, and Thomas D. Willett, "Optimal Leasing Policy for the Development of Outer Continental Shelf Hydrocarbon Resources," Land Econ. 51:191-207, 1975.)

<sup>70</sup>Smith, "Risk Aversion and Bidding Behavior," p. 252.

<sup>71</sup>*Ibid.*, p. 258.

Firms bidding on offshore leases face three types of uncertainty:

- the size of the petroleum deposit;
- the cost of exploration and development; and
- future petroleum prices.<sup>72</sup>

There is very little North Carolina can do about the third item, but the state does have several options for reducing uncertainty associated with the first two. Changes could be made in how exploration is conducted to provide better information at less cost, through government funding or facilitation of cost-sharing among companies. The state should try to minimize what Dam calls the risk of state repudiation,<sup>73</sup> the possibility that the state will later try to alter the effective terms of the agreement through legislation, such as passage of a substantial severance tax. The state cannot eliminate this risk, but it can reduce the perceived risk by reviewing such matters thoroughly and making recommended changes before the lease sale. Most importantly, the state can minimize the uncertainty associated with administrative and regulatory costs by making a concerted effort before the sale to identify the principal restrictions and conditions that will be attached to permits. The better the track record the state establishes in not imposing major, unexpected regulatory costs after the lease sale, the higher the bids will be in future sales. The efforts of states such as Texas and Alaska to notify bidders of likely environmental restrictions and permit conditions were noted earlier in Section 5.2.

Given these basic considerations about competition and uncertainty, the remainder of this subchapter will examine a number of specific sales policy issues:

- What eligibility criteria for bidding should be established?
- Should the sale be conducted by oral auction or sealed bid?
- What should the bidding variable and the fixed compensation terms be?
- Should a market based refusal price be stipulated?
- Should the bids be publicly opened and announced?
- How should the sale results be evaluated to determine whether and with whom the state should execute a lease?

Two final topics that are mostly mechanical will be reviewed briefly: bidding mechanics and execution of the lease.

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<sup>72</sup>Leland and Norgaard, "Outer Continental Shelf Petroleum Leasing Policies," p. 25.

<sup>73</sup>Dam, Oil Resources, pp. 175 ff.

## Bidder Eligibility Criteria

Eligibility criteria for bidders can be used to pursue a variety of objectives, and three of the seven major offshore programs utilize them to some extent (Table 5-10). While the other four programs have no explicit criteria, other state laws may serve the same purpose. Any company desiring to bid on Louisiana leases, for instance, must be registered to do business in that state.

The possible use of a criterion requiring a good environmental record was discussed in Section 5.3. Criteria used by other leasing programs include:

1) Due diligence. The Outer Continental Shelf Lands Act Amendments of 1978 state that: "No bid for a lease may be submitted if the Secretary finds, after notice and hearing, that the bidder is not meeting due diligence requirements on other leases."<sup>74</sup> This provision reflects concerns raised several times after the 1973 oil embargo that some companies were withholding production to create an artificial scarcity. A study at Interior led to the cancellation of two leases in the Gulf in June of 1977 for lack of drilling activity, and a study by the National Academy of Sciences and National Academy of Engineering concluded that in at least one of the six gas fields reviewed, accelerated production of natural gas was warranted.<sup>75</sup> Proponents of the due

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Table 5-10

### Requirements for Bidder Eligibility

<u>Program</u>	<u>Due Diligence</u>	<u>Legal Status</u>	<u>Joint Bidding</u>	<u>Acreage Limit</u>	<u>Financial Ability</u>	<u>Equal Opportunity</u>
Alabama						
Alaska		X		X		
California		X			X	
Louisiana						
Mississippi						
Texas						
U.S.	X	X	X			X

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<sup>74</sup>Codified at 43 U.S.C. §1337(d).

<sup>75</sup>Robert B. Krueger and Louis H. Singer, "An Analysis of the Outer Continental Shelf Lands Act Amendments of 1978," Nat. Res. J. 19:909-927, 1979.

diligence clause claim that the federal government, as a landowner, should have the right to reject prospective lessees who are not meeting their obligations elsewhere, in the interests of maximum revenue and efficient management. No states have followed suit.

2) Legal status. The U.S., Alaska, and California all require that bidders qualify in one of several legal categories.<sup>76</sup> OCS leases, for instance, can only be held by U.S. citizens, nationals, permanent resident aliens, corporations organized under federal, state, or territorial laws, and associations of the above. The lists of permissible categories in Alaska and California are slightly different; both of those states, for instance, also include citizens of other countries which grant similar privileges to U.S. citizens.

3) Joint bidding. The U.S. has banned joint bidding among certain majors to promote competition.<sup>77</sup>

4) Acreage limit. Alaska limits the lease holdings of any person or corporation to 500,000 acres of tide and submerged lands and 500,000 acres of other state lands.<sup>78</sup>

5) Financial ability. California requires the top three bidders for each tract to submit a financial statement demonstrating the bidder's ability to undertake the operations and obligations of the lease. Other programs rely on the various bonds required of the lessee to protect the state against financially unfit firms.

6) Equal opportunity. Bidders at OCS lease sales are required to show compliance by the firm with the equal opportunity/affirmative action regulations of the Department of Labor.<sup>79</sup>

California and the U.S. require that paperwork establishing a bidder's eligibility be submitted no later than at the time of the sale itself. Alaska, on the other hand, requires prospective bidders to "pre-qualify" by establishing their eligibility at least the day before the sale. This allows the state at the time of the sale to determine immediately whether a high bidder is qualified, and if so, to return the deposit checks of the unsuccessful bidders. Should North Carolina choose to establish eligibility criteria, it is recommended that bidders be required to establish their eligibility before the sale.

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<sup>76</sup>30 CFR 256.35(b); 11 AAC (Alaska Administrative Code) 82.200; Calif. Public Res. Code §6801.

<sup>77</sup>See note 63, above.

<sup>78</sup>Alaska Stat. §38.05.140(c); 11 AAC 82.300-.310.

<sup>79</sup>41 CFR §60-1 and Executive Orders 11246 and 11375.

## Sealed Bid vs. Oral Auction

Walter Mead's 1967 paper on oral versus sealed bidding in natural resource auctions is the definitive discussion on the subject, and much of what follows is based on his exposition.<sup>80</sup>

The key characteristics of oral bidding are that the bidders know who their competitors are during the course of the sale, and that a bidder has an opportunity to respond to competitors' bids with a higher one of his own. These traits lead to several undesirable characteristics of oral auctions. First, they facilitate such practices as collusion (by allowing conspirators to police the agreement and react if someone breaks it), implicit bargaining (the use of bids to signal to others a firm's intentions), preclusive bidding (the use of a high initial bid to make entry expensive or impossible for another), and punitive bidding (the punishment of a participant for some past transgression by bidding up the price of items of special interests to the offender).<sup>81</sup> Where there is only one bidder, he will win the tract at just above the announced reservation price. If that price is difficult to set realistically, as it is with oil and gas rights, the bidder may get a bargain. With oil and gas properties there is also the "free rider" problem. Where large exploration expenses are necessary before a sale, a bidder can avoid these by bidding incrementally over other bidders on the assumption that others will not bid more than what their exploration results indicate the tract is worth. Finally, oral auctions require the presence of someone authorized to make immediate, sometimes major decisions.

In general these problems are most severe when the level of competition is low. Changes in the conduct of oral auctions have been suggested that might alleviate some of these problems. These include electronic oral bidding, in which bids are submitted electronically from different locations with the identities of bidders kept secret, and the use of sealed government reservation prices that are opened only after the bidding is closed.<sup>82</sup>

On the other hand, there are two principal advantages of oral bidding. The individual bidder has the opportunity to react to other bids and increase his own where he has an additional incentive to win. This is particularly important in industries structured like the timber industry, where an operator generally has a large, fixed investment in a mill and only the timber within a short radius available to him because of high transportation costs. In these cases, it is important that an operator have control over whether he wins or loses a particular tract, as a failure to win enough tracts nearby may mean

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<sup>80</sup>Walter J. Mead, "Natural Resource Disposal Policy -- Oral Auction Versus Sealed Bids," Nat. Res. J. 7:194-224, 1967.

<sup>81</sup>Preclusive and punitive bidding and the possibility of emotional excesses during bidding Mead cites as disadvantages of oral auctions. Though they result in higher government revenues, Mead contends that they result in lower long-term revenues by reducing competition and/or by damaging a firm's financial ability to develop a tract.

<sup>82</sup>McDonald, Leasing of Federal Lands, p. 78; Mead, "Natural Resource Disposal Policy," p. 201.

his ruin. This is not true of the oil and gas industry. Secondly, bidders can adjust their bidding on subsequent tracts based on whether they have already won enough or whether they still have capital and facilities available to handle more.

Sealed bidding avoids many of the problems of oral auctions. Bidders do not know who their competitors will be, and they have only one chance to bid, with no opportunity to respond. Under these circumstances, a bidder is strongly motivated to enter a bid closely approximating his valuation of a tract, suitably discounted for risk. Collusion and implicit bargaining are more difficult, as there is no opportunity to send signals or police an agreement during the course of the auction. Such unfair practices as preclusive and punitive bidding are also restrained. In the single bidder situation, the government may still get close to a competitive price because of the bidder's uncertainty about the number of his competitors. The free rider problem is completely eliminated.

These advantages may have been overstated, because particularly in submerged lands leasing, bidders are often well informed about the number of potential bidders as a result of pre-sale exploration. It has already been noted that bids are often adjusted for the expected degree of competition. Bidders may also adjust them for the bidding strategies of their expected competitors, as determined from previous sales.

The major disadvantage of sealed bidding is that in multi-tract sales, a bidder must choose between bidding on enough tracts so that the fraction it expects to win will match the firm's resources, in which case it runs a danger of becoming over-committed, or else bidding on fewer tracts to be safe, in which case it will probably win fewer than it could develop, and the overall level of competition will be reduced in both the short- and long-term.<sup>83</sup> This is primarily a disadvantage of bonus bidding, and with royalty and profit-share bidding financial constraints are presumably not as severe. The difficulty may be partially resolved with sequential bidding, in which, after the bids on one tract are opened and announced, bidders are given the opportunity to submit bids for the next tract.<sup>84</sup>

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<sup>83</sup>McDonald, Leasing of Federal Lands, p. 81.

<sup>84</sup>Ibid., p. 108. The order of bid opening might be determined by the number of bids submitted, a vote of bidders, random selection, or other means. To minimize possibilities for collusion, signalling, and similar practices, just the amount of the winning bid could be announced following each round, or each bidder could even be informed privately whether he had won or lost. The disadvantages of sequential bidding are that the process of awarding leases becomes cumbersome and time-consuming, those attending lease sales must have the authority to make major decisions rapidly or come equipped with complex contingency plans, and it may be difficult to accompany each bid with a deposit in the required form.

McDonald contends that sequential bidding would increase the average number of bids per tract and the level of the average winning bid. California has used sequential bidding in pre-Santa Barbara sales. The U.S. Department of Energy proposed an experimental sequential bidding procedure for OCS sales (44 Fed. Reg. 52842, 1979), but the procedure never received final approval.

The conclusion to be drawn from Mead's analysis is that for a sale in which competition may be weak, where a realistic refusal price is difficult to set, where firms do not have major stakes in acquiring specific items, and where free riders may be a problem (all of which apply to oil and gas lease sales in North Carolina), sealed bids are preferable. The oil and gas industry has stated its preference for sealed bids.<sup>85</sup> Sealed bidding is used in all seven of the major offshore leasing programs examined and is statutorily required in five of them. It is recommended for use in North Carolina as well, possibly modified to include a sequential bidding procedure.

#### Bidding Variable and Fixed Terms

An issue that has received a great deal of attention from policy-makers and economists is the question of optimal bidding systems. It is clear that under the assumptions of perfect competition, perfect information and foresight, no tax distortions, and perfect capital markets, the standard practice of cash bonus bidding would work exceptionally well and there would be no need to consider alternatives. The bonus offered would be the present value of a tract's net cash flow, which is the economic rent a bidding system should ideally capture.<sup>86</sup>

However, many of these assumptions do not hold because of the nature of petroleum discovery, the petroleum market, and the structure and function of the petroleum industry. As a result, several different bidding systems have been examined and tested for their performance in terms of the objectives listed earlier. The advantages and disadvantages of the three major bidding variables will be examined first, assuming in each case the other fixed terms are negligible. Other options and combinations will then be considered.<sup>87</sup>

Bonus Bidding. Relatively pure bonus bidding has several key characteristics. By requiring a front-end payment regardless of future discoveries, it places virtually all of the risk on the lessee. The uncertainty associated with petroleum discovery is apt to depress the amount of bonus offered to a greater extent than would occur if a contingent payment such as a royalty or profit-share comprised the major portion of compensation. The large bonuses required for promising tracts will also tend to operate as barriers to entry by smaller firms, thereby restraining competition.

The great advantage of bonus bidding is that the bonus, once paid, becomes a sunk cost that is irrelevant to future exploration, development and production decisions. (A slight exception is that on surrendered tracts the

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<sup>85</sup>Mead, "Natural Resource Disposal Policy," p. 219.

<sup>86</sup>Robert J. Kalter, Wallace E. Tyner, and Daniel W. Hughes, Alternative Energy Leasing Strategies and Schedules for the Outer Continental Shelf, Cornell Univ. Ag. Expt. Sta. Research Rpt. 75-33 (Ithaca, N.Y.: Cornell Univ., 1975) (NTIS: PB 253315), p. 47; McDonald, Leasing of Federal Lands.

<sup>87</sup>Much of the following discussion relies heavily on McDonald, Leasing of Federal Lands, except where noted.

bonus can be written off immediately, thereby biasing the decision in favor of abandonment of marginal properties.) The lack of royalty or profit-share payments gives the operator the greatest incentive for efficiency.

Royalty Bidding. Royalty bidding, on the other hand, results in a sharing of risk with the government. Exploration costs are risked solely by the operator, but no compensation is due the government unless petroleum is found and produced. The reduced risk and lower cash requirements not only lower the entry barriers to firms, but also lower the risk premiums, so that firms will tend to bid a higher proportion of the expected economic rent.

There are several disadvantages to royalty bidding. Since the royalty payment is part of operating costs, properties that would turn a marginal profit without a royalty may be unprofitable with one. The result is that fields may be abandoned early (as production declines and costs rise) or not developed at all, with a net loss to society. Most leasing programs have the authority to lower royalty rates so as to prevent early abandonment, but if this is done regularly the system will break down, as firms will bid whatever is needed to win a tract and rely on the public agency to lower the royalty later to make production profitable. There is also a danger with royalty bidding that some firms will bid very high with hopes of making a major find, and then abandon the tract if minimal exploration suggests such a find is unlikely. Finally, different royalties on adjacent tracts make unit operation difficult, promote drainage of reserves from high to low royalty tracts, and may encourage inefficient drilling and platform locations.<sup>88</sup>

Profit-share bidding. As explained in Section 5.1, under a profit-share agreement the lessee pays the lessor a fixed percentage of the profits realized on the lease. These profits may be calculated in three ways: (1) The IRS definition may be used, in which profits are gross revenues minus operating costs and capital consumption allowances. Under current IRS rules, some exploration and development costs may be expensed currently, while others must be depreciated. (2) Under a fixed-capital recovery plan, the lessor shares in gross revenues minus operating costs, but only after the total capital investment, multiplied by some factor usually greater than 1, has been recovered by the lessee from operating profits. (3) With an annuity capital recovery system, total capital outlays with accumulated interest are converted when production begins into an annuity with a specified interest rate and term, and the amount of the annual annuity is subtracted from each year's operating profits, with the remainder serving as the profit-share base. It should be evident that the fixed-capital recovery plan provides the lessee with the best assurance of a certain return on investment, with the annuity system next and the IRS system last. The fixed-capital recovery system is the most common in use.

Profit-share bidding possesses many of the characteristics of royalty bidding. With no front-end payment and a shift of some risk to the government, entry barriers and risk premiums are lower than with bonus bidding, resulting in more competition and capture of a higher proportion of economic

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<sup>88</sup>Minerals Management Service, "Report to Congress, 1982," p. 22.

rent by the government. Also like royalty bidding, profit-sharing may result in early abandonment or no development at all of marginal properties. Profit-shares are superior to royalties in this respect, as costs are at least taken into account; among profit-share methods the annuity and fixed-capital systems rank highest, in that these make some provision for a normal return on investment. However, these same characteristics make excessive bidding even more likely with profit-sharing. The incentive for efficiency is also considerable reduced. On the other hand, with government given a stake in lease profits, regulatory costs may be restrained.

The major practical difficulty with profit-sharing, regardless of whether it is a fixed term or bidding variable, is the government oversight required. Since expenses charged to a lease cost the lessee only the fraction that is it's profit-share, the lessee is motivated to charge as many expenses as possible to the lease. The lessor, therefore, must monitor the lessee's financial records and establish detailed rules for allowable expenses. These rules run to 14 pages in the Code of Federal Regulations and to 39 pages in the most recent California lease.

Combinations. In fact, it is rare that one of these terms is used as the sole method of compensation. In most bidding schemes, one type of compensation is selected for the bidding variable, and one or both of the other two, as well as a delay rental, are included as fixed terms and announced before the sale. The resulting bidding systems tend to have some of the advantages and disadvantages of each of the methods included. A few of the more common bidding systems are discussed below.

(1) Bonus bidding with a substantial fixed royalty. As seen earlier, bonus bidding (with no royalty) is superior to royalty bidding (with no bonus) with respect to its effect on the margin of development and production, but inferior because of higher capital requirements and risk. The best option may be somewhere in between, perhaps near what has been the standard bidding system for many years, bonus bidding with a fixed royalty of 1/8 or 1/6.<sup>89</sup> One problem with a fixed royalty in this situation is that it is difficult to set it high enough to transfer a large portion of the risk to the government without setting it so high that the margin of development is seriously affected.<sup>90</sup>

(2) Bonus bidding with a substantial fixed profit-share. This system is similar to the preceding one. It is slightly superior with regard to its effect on the margin of development and production, but inferior with regard to administrative cost.

(3) Bonus bidding with a sliding scale royalty. A sliding scale royalty is one in which the royalty rate during any period varies directly with the value or amount of production in that period. The advantage of sliding scale royalties over fixed rates is that the royalty can be set high for very productive tracts, yet low enough on marginal tracts so as to not seriously

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<sup>89</sup>McDonald, Leasing of Federal Lands, p. 102.

<sup>90</sup>Kalter and others, Alternative Energy Leasing Strategies, p. 49.

affect development or abandonment decisions. In frontier areas like North Carolina sliding scale royalties allow low potential tracts to be leased for modest sums while protecting the state against a give-away if a substantial find is made. The major disadvantage of sliding-scale royalties is that they are not neutral with respect to decisions on development and the time distribution of production, and may induce less than socially optimal behavior regarding the rate of extraction.<sup>91</sup>

(4) Royalty bidding with a substantial fixed bonus. The major question regarding use of this system is whether the bonus can be set high enough to prevent excessive royalty bids yet not so high as to bar entry to the smaller firms that royalty bidding is intended to attract. The federal government has experimented with royalty bidding in two OCS sales. In the first, OCS Sale 36 in October 1974, ten tracts were offered under royalty bidding with the bonus set at a modest \$25/acre. Analysis of the results led Interior to conclude that tracts with royalty bidding had attracted more bidders than similar tracts offered under bonus bidding, but that royalty bidding did not appear to increase the relative success of independent operators.<sup>92</sup> For the eight tracts that received royalty bids, the U.S. Geological Survey estimated that the royalty rates that could be expected to generate a normal rate of return were in the neighborhood of 20%. The winning bids in fact ranged from 51.8% to 82.2%. USGS's analysis estimated that losses in the present value of resources as a result of early abandonment, nondevelopment, and slowdowns in exploration induced by these high royalty rates amounted to approximately 50%.<sup>93</sup>

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<sup>91</sup>There are several types of sliding scales in use. The Minerals Management Service uses a scale of the form

$$R_j = b[\ln(V_j/S)]$$

where  $R_j$  = royalty percentage in quarter  $j$ ,  
 $V_j$  = inflation-adjusted production value (\$million) in quarter  $j$ ,  
 $b$  = a sliding scale coefficient that determines the slope of the curve, and  
 $S$  = a scale factor that sets the initial point at which the royalty rate exceeds the minimum.

Such a scale is sensitive to increases in both the real value of the resource and the volume of production. Non-linear scales are preferred because they can ameliorate the incentive created by linear forms to slow the rate of production.

MMS has been using sliding scale royalties increasingly as an alternative to the fixed royalty system. The agency has examined and experimented with several different scales in its attempts to find ones that substantially lower capital requirements (i.e., bonus bids) with minimal effect on investment and production decisions. (Minerals Management Service, "Report to Congress, 1982," pp. 24-25.)

<sup>92</sup>McDonald, Leasing of Federal Lands, p. 100.

<sup>93</sup>Minerals Management Service, "Report to Congress, 1982," p. 22.

The second royalty bidding experiment was conducted in the Cook Inlet Sale of 1977. Bonuses on these tracts were set substantially higher, and as a result of this and the high costs of Alaskan OCS development, winning royalty bids averaged about 40%. Such bids were still deemed to be high relative to the costs of production, and were estimated to have resulted in losses in the present value of resources of 10-20% above those induced by a traditionally low fixed royalty. Moreover, sale results did not indicate any significant difference in the levels of competition between bonus and royalty bid tracts.<sup>94</sup>

(5) Profit-share bidding with a substantial fixed bonus. This is similar to the preceding system and will tend to have similar problems. The likelihood of premature abandonment is reduced, but the incentive to bid excessively high is even greater.

There are a variety of other schemes that have been proposed, a few of which have been tried but none of which have caught on, at least in this country. These include rental bidding, bonus or royalty bidding with high delay rentals, royalty bidding on a multiple of a sliding scale, work commitment bidding, working interest bidding, bonus bidding using installment payments with a forgiveness option, and others. Several publications discuss these options.<sup>95</sup>

A different type of system from those discussed so far is dual bidding, in which bidding is conducted on two or more bid variables simultaneously. Alabama, for instance, required that bids be submitted on both the cash bonus and royalty for tracts offered in its 1981 offshore sale. Louisiana permits bidding on the cash bonus, royalty, and rental simultaneously, and also allows other obligations (e.g., work commitment, depth limitations) to be included and considered. On the other hand, some programs are statutorily forbidden from using dual bidding.

The advantage of dual bidding, as advanced by its proponents, is that it provides the state with additional flexibility in obtaining the offer most advantageous to the state. The obvious disadvantage is that bid evaluation is made more difficult. Industry is firmly opposed to it as it involves the additional task of guessing what administrators are looking for in a bid. This additional uncertainty may undermine general confidence in the selection process and may lead some firms to decide that bidding is not worth the cost involved. It is recommended that North Carolina join the majority of states in not using dual bidding.

There are studies galore on the advantages and disadvantages of different leasing systems, each based on its own particular models and with its own sets of assumptions and recommendations. There is also a wealth of experience to be culled from other leasing programs (Table 5-11). At this point a firm recommendation for a single bidding system to be used in North Carolina cannot be made, as any system should be tailored to the particular circumstances

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<sup>94</sup>Ibid., pp. 22-23.

<sup>95</sup>See McDonald, Leasing of Federal Lands, and Kalter and others, Alternative Energy Leasing Strategies.

Table 5-11. Bidding Systems Used by Selected Leasing Programs, 1970-1983

<u>Bidding System</u>	<u>Alabama</u>	<u>Alaska</u>	<u>California</u>	<u>Louisiana</u>	<u>Mississippi</u>	<u>Texas</u>	<u>U.S.</u>
Bonus bidding with fixed royalty		X			X	X	X
Bonus bidding with sliding scale royalty		X					X
Bonus bidding with fixed net profit share							X
Bonus bidding with fixed royalty and net profit share		X					
Royalty bidding with fixed bonus		X				X	X
Net profit share bidding with fixed bonus			X*				
Net profit share bidding with fixed bonus and royalty		X					
Dual bidding	X			X			

\*Point Conception leases were to be awarded on the high net profit share bid with no official bonus or royalty. The first three years' rentals on each lease, however, were very high and were due regardless of circumstances, making them in effect a fixed bonus payable in three annual installments.

surrounding the leases to be sold. Some of the major considerations that should enter into this decision have been discussed above. Based on these considerations and various studies and experience, however, two general recommendations are ventured for initial lease offerings in this state. First, net profit-share payments, despite a number of advantages, are administratively too difficult and cumbersome to be handled well by a fledgling and probably part-time program, and should not be included in any lease. Second, a sliding scale royalty has much to recommend it and should be considered as a serious alternative to the traditional fixed royalty with bonus bidding.

Finally, a word should be said about severance taxes. Severance taxes are taxes imposed on the removal of natural resources (oil and gas, timber, coal, etc.) and levied on the basis of the quantity or value removed. Twenty-

seven states currently have some form of severance tax on oil and/or gas, ranging as high as 15 percent for some types of oil wells in Alaska.<sup>96</sup> In North Carolina the Department of Natural Resources and Community Development is currently authorized to levy a tax of \$.005 per barrel of oil and \$.0005 per 1000 cubic feet of gas produced to pay the administrative costs of the Oil and Gas Conservation Act.<sup>97</sup> More substantial rates have been a topic of discussion for several years.

Severance taxes function essentially like royalties, and for production on state-owned land merely replace an equal amount of royalties that the state could otherwise extract from the lessees. Their major difference is that they also produce state revenues from production on private lands. The basic theory of severance taxes is that the current and future costs of resource development, including asset replacement costs, should be borne by the users of that resource. In keeping with that notion, several states place severance tax revenues in permanent trust funds, with the income used for a variety of purposes, including economic development, energy impact mitigation, education, and as a supplement to the general fund.<sup>98</sup>

Severance tax debates make oil and gas operators understandably jittery, since a severance tax can be a major cost of production and can be imposed unilaterally, and at any time, by the state. In designing an oil and gas program the state should carefully consider whether additional severance taxes are appropriate, and should make an attempt to review the matter and settle the question for the foreseeable future before any sales are held.

#### Market-Based Refusal Price

In some natural resource auctions, a market-based refusal price is announced before the sale to inform bidders of the minimum amount the public agency is willing to accept, thereby setting a floor for bidding (particularly in oral auctions) and saving some firms the time and effort of preparing bids. Refusal prices are most common in oral auctions of timber.<sup>99</sup>

There are two reasons why refusal prices should not be announced before a sealed bid oil and gas sale. First, the problems of establishing a realistic refusal price before the sale are formidable. As noted before, accurate appraisal of oil and gas properties without exploratory drilling is very difficult. Often compounding the problem is the public agency's lack of geologic information or the manpower and time to interpret it. In many cases

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<sup>96</sup>Earl E. Starch, Taxation, Mining, and the Severance Tax, Bureau of Mines Information Circular 8788 (Washington, D.C.: Bureau of Mines, U.S. Department of the Interior, 1979), pp. 50-54.

<sup>97</sup>N.C. Gen. Stat. §113-387.

<sup>98</sup>Richard V. Watson, "The Use of Royalty and Severance Tax Revenues," Legislative Finance Paper 10, National Conference of State Legislatures Fiscal Affairs Program, Denver, Colorado, 1982.

<sup>99</sup>Mead, "Natural Resource Disposal Policy," pp. 200-201.

government even uses the bidding results themselves to help determine whether high bids are adequate. Secondly, even if a realistic refusal price could be determined before a sale, by keeping it secret the public agency essentially becomes a bidding participant, effectively increasing competition and the general level of bids, particularly in low interest areas.<sup>100</sup>

While several of the major offshore programs stipulate minimum bids, all reserve the right to reject any bids deemed insufficient. The stipulated minimum bids in these cases tend to be standard (in some cases statutory) values and serve to place a floor under bidding without removing the uncertainty surrounding acceptance of the high bid. Whether such stipulated minimums have any utility is not known. It is recommended that North Carolina, like other offshore programs, not announce refusal prices before the sale; the state may wish to experiment with announced minimum bids.

#### Public Announcement of Bids

In the seven offshore leasing programs examined, all bids are publicly announced at the sale. The advantages of bid disclosure are that it reinforces public confidence in competitive bidding, allows public oversight, and provides an indication of how competitive the bidding is and how government acceptance or refusal relates to bid numbers and amounts.

However, several arguments can be advanced in favor of keeping all but the winning bids confidential. Public disclosure allows companies to analyze the bidding patterns of their competitors and adjust their future bids accordingly, most probably to the detriment of government receipts.<sup>101</sup> In addition, if bids are not announced, the amount by which the winning bid exceeds the second highest bid, known as money "left on the table," will not be known. Mead notes that "the real attitude of land men toward 'leaving money on the table' is one of considerable embarrassment leading one to remark, 'I'd rather lose a lease than leave money on the table.'"<sup>102</sup> If this attitude is prevalent, public disclosure may result in lower bids. Even if losing bids are not announced government manipulation is impossible, as losing bidders will object if a winning bid lower than theirs is announced. For these reasons Alberta has adopted a policy of announcing only the winning bid on each tract, and it is recommended that North Carolina do likewise.<sup>103</sup>

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<sup>100</sup>Douglas K. Reece, Leasing Offshore Oil: An Analysis of Alternative Information and Bidding Systems (New York: Garland Publishing, 1979), 127 pp.

<sup>101</sup>Mead, "Natural Resource Disposal Policy," p. 211.

<sup>102</sup>Ibid., p. 212. A spectacular example of money "left on the table" occurred on tract 17 in OCS Sale 56 off North Carolina, where the winning bid of \$103.8 million by a group led by Mobil exceeded the next highest bid by more than \$76 million.

<sup>103</sup>This will require a statutory exception to N.C. Gen. Stat. Chapter 132. The following language to cover this situation and the identities of applicants (p. 46) could be added as an amendment to N.C. Gen. Stat. §146-8:

## Selection of the Lessee

Once the bids have been opened, the public agency must decide who, if anyone, will be offered a lease. There are several considerations:

(1) Who is the high bidder? The success of competitive bidding depends on the fact that, assuming bidders are qualified, the winner is determined only by the size of the bid. For all seven offshore programs, the appropriate statutes or regulations require that if any bid is accepted, it must be that of the "highest responsible qualified bidder" (Alaska, U.S.) or "the bid most advantageous to the state" (Louisiana, Mississippi). Where bidding has been conducted on only one variable, the high bid is immediately evident.

Tie bids are very unlikely, but several programs make provision for them nonetheless. If the highest bids for an OCS tract are tie bids, MMS requires that the bidders agree to accept the lease jointly, or else all bids are rejected. In Alaska, tied bidders are invited to submit new bids at least as high as their original bids within 30 days; if the tie is not broken, the Commissioner may repeat the procedure or award the lease by lot at a public drawing. Should the highest bids be tied in Texas, all bids are rejected and the tract is made available for lease again within several weeks, with a minimum bid set equal to the previous high bid.<sup>104</sup>

Assuming the high bids are adequate, the state has an interest in seeing that a tie-bid tract is leased, and at the highest price and in a fair manner. The following procedure is therefore proposed for North Carolina. If the highest bids on a tract are tied, the tied bidders should be invited to submit new bids at least as high as those already offered. If these are also tied, the procedure should be repeated or, at the Secretary's discretion, the bidders should be asked to accept the lease jointly; if they refuse, the lease should be awarded by lot.

(2) Is the bidder qualified and has the bid been properly submitted? If eligibility was required to be established before the sale, these questions can be answered with a quick reference to the appropriate file. Otherwise, eligibility may take several days to establish.

(3) Is the bid sufficient? The question of bid adequacy is a very complex and occasionally controversial one. There are several approaches that make use of geologic information, comparable values from nearby leases, sale results, and other information. The subject will not be discussed further here, and the interested reader is referred to the recent report on bid adequacy issued by MMS.<sup>105</sup> If all bids are rejected as insufficient, Alaska

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If a system of competitive bidding is used to allocate mineral rights, information related to the identity of applicants and the identities and bids of unsuccessful bidders shall not be considered public records within the meaning of Chapter 132 of the General Statutes.

<sup>104</sup>30 CFR 256.47 (U.S.); 11 AAC 82.455 (Alaska); Tex. Nat. Res. Code Ann. title 2, §52.019 (Texas).

<sup>105</sup> U.S. Department of the Interior, Minerals Management Service,

and Louisiana law both permit the tract to be immediately offered again for lease on a competitive basis, with the requirement in Louisiana that no bids may be lower than the rejected high bid. This provision has merit, if used sparingly, in allowing the government to pursue an adequate bid for a tract it is interested in leasing without repeating the entire review process, and is recommended for North Carolina.

(4) Are there anticompetitive implications in issuing a lease to the high bidder? After every OCS lease sale, the U.S. Attorney General, in consultation with the Federal Trade Commission, is given 30 days to review sale results to determine "the likely effects the issuance of such leases would have on competition," and to make recommendations to the Interior Secretary "as may be appropriate to prevent any situation inconsistent with the antitrust laws."<sup>106</sup> While antitrust problems are less likely in North Carolina than on the OCS, they could conceivably arise, and the N.C. Justice Department should be consulted at least informally before a sale as to what circumstances would merit further review.

#### Bidding Mechanics

Detailed bidding instructions should be published with the notice of sale. Most programs also issue bid forms or sample bids for illustration. At a minimum bids should include: the lease sale number, the tract bid on, the amount of the bid (to a suitable number of decimal places if a royalty or profit-share bid), the amount of the enclosed deposit, the name, authorizing signature, date, and qualifications file number of the bidder, and if a joint bid, each of the last four items for each partner, along with the proportionate interest of each. It is also useful to require instructions for filling out and sending the lease (if the bid is successful) or for returning the deposit (if it is not), and the name of the agent authorized to receive notices on behalf of the bidder(s).

All programs require that a deposit be submitted with the bid as evidence of the bidder's good faith. These generally vary from 20% to 100% of the cash bonus, depending on the program.<sup>107</sup> Deposits of unsuccessful bidders are

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Procedures for OCS Bid Adequacy, Including the Final Report of the OCS Fair Market Value Task Force (Washington, D.C.: Minerals Management Service, 1983), various pagings.

<sup>106</sup>43 U.S.C. §1337(c); see D.A. Kaplan, "Justice Department Review of Federal Coal and Oil Leasing: Serving the Consistent Goals of Competition and Energy Independence," Nat. Res. Lawyer 13:685-693, 1981.

<sup>107</sup>The deposit required by different programs in recent sales is:

Alabama	-	50% of the cash bonus
Alaska	-	20% of the cash bonus
California	-	\$50,000 (Point Conception Sale)
Louisiana	-	100% of the cash payment (of which the cash bonus and first year's rental comprise equal portions)
Mississippi	-	100% of the cash bonus
Texas	-	100% of the cash bonus and 1 1/2% as sale fee
U.S.	-	20% of the cash bonus

returned after the sale; those of successful bidders are applied to the bonus payment if leases are executed within the time specified, and are forfeited if they are not. In some cases the deposit will be substantial, and because of interest expense it is important that deposits of unsuccessful bidders be returned as quickly as possible. In most programs, the second highest bidder can only be offered a lease if the highest bidder is found ineligible. In programs like Alaska, then, where bidders must pre-qualify, the eligibility of the high bidder can be determined immediately, and deposits are generally returned the afternoon of the sale. Programs with eligibility criteria but no pre-qualification requirement will generally take several days. Similarly, evaluation of high bids should also proceed quickly so that deposits of rejected bidders may be returned. Time needed for this step may range from a week in Alaska to as much as 90 days for the OCS program. After a certain period of time (7-10 days?) interest should be included in any refund.

#### Execution of the Lease

The successful bidder, once notified of his bid's approval, is usually given a specified period of time after receipt of the lease to execute the lease, pay the balance of the cash bonus and the first year's rental, and file any required bonds. Alaska, California, and the U.S. each require a surety bond conditioned upon faithful compliance with all provisions of the lease, while the other four leasing programs do not.<sup>108</sup> Such a bond protects the state in the event that a lessee suddenly goes bankrupt or refuses to meet his obligations, and it is recommended that North Carolina require a lease bond as well. Two other bonds may also be required of the lessee during the permitting stage, either by the leasing agency or other state authorities: a drilling bond for each well drilled, and a bond or insurance to cover potential oil spill clean-up costs and damages.

#### Recommendations

##### The Leasing Process: Application and Review

1. Pre-application contacts. These should be the responsibility of the Division of Land Resources, and should include advice on the leasing process, permits required for exploration and development, and the geologic information already available from previous exploration. P. 47.
2. Application. Areas to be considered for lease should be determined primarily by unsolicited applications from industry. Applications should include (a) the area to be offered for lease, (b) qualifying information required of all bidders, and (c) a deposit on each block nominated, to be

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<sup>108</sup>30 CFR 256.58-.61 (U.S.); 11 AAC 82.465, 82.600, and 83.160 (Alaska); Calif. Public Resources Code §6829(d) (California). The amounts required are, for the OCS: \$50,000 per lease or \$300,000 per OCS area; for Alaska: a minimum of \$10,000 per lease (may be increased by the Commissioner) or \$500,000 statewide; for California Point Conception leases: \$100,000 per lease plus up to 50% of the replacement cost of fixed structures.

returned if the block is not offered or if the applicant bids on it, regardless of whether he wins. The identity of the applicant should be kept confidential. Pp. 45-47.

3. Preliminary review. Upon receipt, the application should be referred to the Division of Land Resources for conduct of the preliminary review, with assistance from others as appropriate. The preliminary review should consist of determinations as to (a) completeness of the application; (b) other, unnominated areas the state may wish to consider for leasing at the same time; (c) property rights in the area proposed for lease; (d) condition of the market for offshore leases; and (e) compatibility of the proposal with explicit departmental policies on leasing. A recommendation to proceed with review, with an accompanying timetable, or a recommendation to defer because of poor market conditions should be forwarded to the Secretary for his concurrence. Pp. 46-48.

4. Substantive review. If the Secretary approves the proposal for substantive review, he should refer it either to an appointed task force or the existing OCS Task Force to conduct the review and advise him as appropriate. Anticipated changes in SEPA regulations make specific recommendations for review procedures difficult. For illustration, recommended procedures assuming an NRCD task force and existing SEPA rules are shown in Figure 5-3 (p. 54) and consist largely of existing departmental procedures for SEPA implementation. The major steps of these recommended procedures are: (1) review of application to determine if leasing is or may be in the public interest; (2) preparation of a Draft EIS (assuming an EIS is required); (3) approval by the Secretary and circulation within NRCD; (4) revision as appropriate and submission of the revised Draft EIS to the state clearinghouse for distribution to state agencies, regional councils, and local governments, with concurrent submission by NRCD to appropriate federal agencies, private groups and others; (5) 60-day review, including public hearing(s) announced in appropriate newspapers and informal meetings of the task force with interested groups (oil and gas industry, fishing and tourist industries, environmental groups, etc.); and (6) review by task force of comments received and decision whether to recommend to Secretary abandonment of proposal or preparation of Final EIS, with concurrent consistency review by Coastal Management. Pp. 52-57.

5. Secretarial decision and notice of sale. If the Secretary decides to proceed with the lease proposal, having considered all relevant factors (p. 58) a Final EIS and proposed notice of sale should be issued, including a brief rationale for the Secretary's decision. The notice should include a description of the areas to be offered, a summary of lease terms, lease stipulations, limitations that will or may be imposed during the permitting stage, and information on how to qualify for bidding, how to bid, and how the sale will be conducted. The proposed notice should be released for public comment through the state clearinghouse and NRCD's own mailing list, and upon receipt of comments revised as appropriate. The notice should then be sent to the Department of Administration and the Governor and Council of State for approval, as required by statute, and a final notice issued by the Secretary and advertised extensively. Pp. 58-59.

6. Formal appeals of leasing decisions should be granted at the discretion of the Department. Pp. 60-61.

7. A proposed timetable for the review process is shown in Table 5-5 (p. 62) a reasonable time frame for the review process, from receipt of an application to the final notice of sale, is estimated to be 14-16 months. The state should consider setting the sale date long enough after the final notice (6-12 months) to permit companies to conduct exploration and prepare bids after the notice has been issued. Pp. 61-63.

#### The Leasing Process: Sale

8. Competition should be encouraged by advertising the sale and, where compatible with other objectives, lowering entry barriers to firms; the latter can be promoted by minimizing eligibility criteria and other rules barring certain bids (particularly joint bids), and by using bidding systems and tract alignments that lower capital requirements and risk. Pp. 94-98.

9. Uncertainty should be reduced to the greatest possible extent (a) by making a concerted effort to foresee and announce before the sale the major environmental restrictions on development that will be imposed on lessees, and (b) by state consideration of ways to promote cost-sharing and perhaps some government funding of exploration. Pp. 98-99.

10. The state should consider what qualifications are desirable for bidders. No specific recommendations are made. Pp. 100-101.

11. The state should use a sealed bidding procedure rather than an oral auction, and should consider experimentation with sequential bidding. Pp. 102-104.

12. The state should tailor the bidding system to the particular characteristics of the sale. Only a single bidding variable should be used on any single tract, profit-share payments should not be used in the first few sales, and the state should give serious consideration to the use of bonus bidding with a sliding scale royalty. Pp. 104-110.

13. A market-based refusal price should not be announced before the sale, though minimum bids may be. Pp. 110-111.

14. Only the winning bid and bidder should be publicly announced. P. 111.

15. To determine who, if anyone, should be offered a lease, sale results should be analyzed with respect to four questions: who was the high bidder, is this bidder qualified and was the bid properly submitted, is the bid sufficient, and are there anticompetitive consequences in issuance of a lease to this bidder? Pp. 112-113.

16. Bids should include the information listed on p. 113. Deposits should be required with each bid and should be returned to unsuccessful bidders as quickly as possible. Pp. 113-114.

17. Once the state has decided whom to offer a lease, the successful bidder should be given a short period of time to execute the lease, pay the balance of the cash bonus and first year's rental (if any), and file a bond conditioned on full compliance with the lease. P. 114.

#### Leasing Considerations: Environmental Protection

18. The state has five different avenues available for environmental protection during oil and gas leasing and should make use of each as appropriate. These are: (1) the decision of which areas to offer for lease; (2) eligibility criteria for bidders; (3) lease terms and stipulations; (4) regulations on operations conducted pursuant to the lease; and (5) other laws, regulations, and permits. Pp. 64-69.

19. In deciding which areas to offer for lease, the difference between leasing an area and permitting drilling within it should be kept in mind. Pp. 64-65.

20. Following review of each rejected application, the state should consider whether the facts of the case warrant promulgation of a temporary moratorium on leasing within certain areas. A moratorium should be established only after a public hearing to examine where, how long, and why the moratorium should be in effect. P. 65.

21. The General Assembly should be requested to authorize NRCD to promulgate rules governing oil and gas operations on state lands. Pp. 66-69.

22. A thorough environmental analysis and review should be conducted before the sale, not only to determine the advisability of the sale but also to identify gaps in existing environmental statutes and regulations and to identify major, likely requirements and restrictions to be imposed on lessees during the permitting stage. Pp. 71-72.

23. The adequacy of regulatory statutes and rules to govern oil and gas leasing of privately owned submerged lands should be reviewed in conjunction with review of the first application, or sooner if needed. P. 72.

#### Leasing Considerations: Area and Rate

24. The state should continue to use an extension of the OCS grid into state waters to delineate block boundaries. The presumption should be that these blocks of 2304 hectares each will be offered individually for lease, but industry should be given the chance to demonstrate that tracts larger than a single block are needed to provide sufficient incentive for exploration and development. Bids on fractions of offered tracts should not be accepted. Pp. 73-77.

25. When a tract is considered for leasing, (a) all claims to property interests in the tract should be investigated and, where conflicts exist, resolved if possible; (b) questions of surface access rights and liability for damages should be researched and fully discussed for the benefit of all parties; and (c) appropriate lease provisions should be included in oil and gas leases (and surface leases and easements as well) to establish and/or clarify the obligations of the parties involved. The state should also make it clear to bidders that it does not guarantee title to the oil and gas rights leased. Pp. 77-83.

26. The state should not make rigid use of checkerboard leasing and surrender requirements, but should apply the principles of these approaches flexibly as the situation merits. Pp. 83-85.

27. Special consideration should be given to leasing tracts adjacent to non-state property that is under or being offered for lease. Pp. 85-86.

28. In deciding how much land to offer for lease and how quickly, the state should consider the effect of leasing rate on government revenues, economies of scale, the ability of the state bureaucracy to review applications and administer leases, and the assimilative capacities of the natural and socio-economic environments. Pp. 86-88.

#### Pre-Sale Exploration

29. The state should require all companies conducting oil and gas exploration in state waters to obtain a permit from the Division of Land Resources. Pp. 89-90.

30. The General Assembly should be requested to enact a statute authorizing NRCD to require confidential disclosure of any and all exploration data and the results of its processing, analysis, and interpretation to the state upon request. Stringent procedures and penalties should be implemented to minimize the possibility of unauthorized disclosure. Pp. 90-93.

## CHAPTER SIX

### Lease Administration

This report has already emphasized several times the importance of working out, before the sale, most of the details of how the lease will be administered and the lessee regulated. With regards to the post-sale phase of a leasing program, there are two principal, related questions to be addressed. They are: how should the responsibilities of the various state and federal agencies with regards to oil and gas lease development be coordinated, and what post-sale authority or control should the leasing agency reserve to itself through lease terms and regulations?

With respect to the first question, the state has major responsibilities in four principal areas:

- 1) Administration of lease provisions. These duties include monitoring lessee activities, collecting payments, and implementing lease provisions and stipulations that provide the state with discretionary authority. These functions can probably be handled most efficiently by Land Resources, with advice from other divisions and departments as appropriate.
- 2) Administration of the Oil and Gas Conservation Act, particularly drilling regulations (currently administered by Land Resources).
- 3) Administration of the state's water and air pollution control statutes (currently administered by the Division of Environmental Management).
- 4) Administration of CAMA and the State Dredge and Fill Act (currently administered by the Office of Coastal Management).

A host of other state and federal statutes also apply (see Chapter 3 and Appendix E), but it is in exercising these four responsibilities, in conjunction with the permitting authority of the Corps, that the state will largely determine how the lessee will develop his lease.

It is essential that restrictions imposed under these authorities be coordinated, to ensure both that the lessee is not unreasonably burdened with redundant or incompatible requirements, and that the state has used its authority to cover as many possible impacts and contingencies as are warranted. There are several means for achieving this coordination, ranging from informal meetings of representatives from state and federal regulatory agencies to use of a "permit of last resort" or to a formal procedure comparable to the Colorado Joint Review Process. A principal function of the Office of Natural Resources Planning and Assessment is permit coordination, and they should be called upon to help devise a coordinating procedure for the permitting stage.

With respect to the second question, there are a number of issues in lease administration that will need to be addressed. These include:

1) Should lessees be required to disclose exploration results to the state and/or to the public? This issue is similar in many ways to the question of pre-sale exploration data disclosure discussed in Section 5.5. The Outer Continental Shelf Lands Act Amendments enacted in 1978 require confidential disclosure of all data and information obtained from lease exploration, development, and production on the OCS.<sup>1</sup> Supporters of this provision claim that the Department of the Interior needs this information on tract resources to protect its interests in the leasing program. However, since a single exploratory well often provides information on more than just the tract it is drilled upon, companies have objected strenuously on the grounds that the right to obtain and protect such data is a valuable asset that is bought along with lease development rights by the lessee. They maintain that it is virtually impossible for government to ensure confidentiality of the data, and that disclosure therefore creates a risk of data loss without compensation, thereby creating a disincentive for certain types of expensive drilling programs.<sup>2</sup>

North Carolina regulations are currently more stringent than the federal ones in some respects and more lenient in others. Copies of data from exploration wells must be submitted to the Department, and confidentiality is guaranteed for only one year and may be extended for only one more. (Federal regulations allow confidentiality for two years for some types of data and ten for others, or until the lease expires, whichever occurs first.)<sup>3</sup> In North Carolina, geophysical results, on the other hand, are not subject to disclosure.

2) Should lessees be required to submit exploration and/or production plans for approval? Several leasing programs require, in addition to various permit applications, that a plan of operations or similar report on proposed activities be submitted by the lessee for government review and approval. Regulations may also require that such reports be accompanied by an environmental analysis of the proposed activities. In Alaska, for instance, a Plan of Operations is required of every lessee. In California, lessees must submit an Environmental Impact Report (under the California Environmental Quality Act of 1970) that addresses all phases of lease development. OCS lessees must submit two plans during the course of lease development, an Exploration Plan and a Development and Production Plan, each accompanied by an Environmental Report, while Mississippi offshore lessees must submit three reports, prior to exploration, appraisal/development, and production.<sup>4</sup>

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<sup>1</sup>43 U.S.C. §1352.

<sup>2</sup>Russell O. Jones, Walter J. Mead, and Philip E. Sorenson, "The Outer Continental Shelf Lands Act Amendments of 1978," Nat. Res. J. 19:885-908, 1979.

<sup>3</sup>15 NCAC 5D .0010; 30 CFR §250.3. The North Carolina regulation does not appear to be supported by a specific statutory exception to Chapter 132 of the General Statutes and may be invalid.

<sup>4</sup>Clause 9 of Alaska standard competitive oil and gas lease and 11 AAC 83.158; Calif. Public Resources Code §21000 et seq.; 30 CFR §250.34; Rule 25(J) of the Mississippi Rules and Regulations Governing Leasing for

The advantages of a plan of operations are that it provides an overview of all operations on the lease and also provides an extra degree of control that can be used to complement the regulatory authority of existing permit programs. It's major drawback is that it introduces an extra layer of paperwork and additional uncertainty, both of which will also reduce bids.

3) What steps are necessary to ensure that royalties are received timely and in the correct amount? Unfortunately the state cannot rely on lessees for accurate production and sales data, accurate computation of royalties, and the timely receipt of royalties owed. Differences in interpretation, mistakes, and the occasional willful withholding of royalties occur. As a result, the state will be compelled to devise a system for ensuring that royalties due are paid promptly or that appropriate penalties are imposed.<sup>5</sup> Policies will also be needed for deciding whether the state should exercise its option of taking royalties in kind and for the disposition of these royalties.

4) What measures should govern lease assignment, extension, suspension, and termination? Most programs require that approval be obtained for assignment of any part of a lease, so that the state may ensure that a lease interest is not subsequently transferred to a party ineligible to bid on it. Procedures are needed for lease extension, suspension, and termination that are fair and that give the lessee sufficient opportunity for hearing and appeal.

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Production or Extraction of Oil, Gas, and Other Minerals from State-Owned Lands, promulgated by the Mississippi Commission on Natural Resources.

<sup>5</sup>Accurate and timely royalty collection has been one of the most difficult problems in the federal oil and gas leasing program and has been addressed by a number of studies. See U.S. Commission on Fiscal Accountability of the Nation's Energy Resources, Fiscal Accountability of the Nation's Energy Resources (Washington, D.C.: The Commission, 1982), various pagings; U.S. Government Accounting Office, Oil and Gas Royalty Collections -- Longstanding Problems Costing Millions, Report AFMD-82-6 (Washington, D.C.: GAO, October 29, 1981), 8 + 33 pp.; U.S. Government Accounting Office, Oil and Gas Royalty Collections -- Serious Financial Management Problems Need Congressional Attention, Report FGMSD-79-24 (Washington, D.C.: GAO, April 13, 1979), v + 60 pp.

## APPENDIX A

### Non-Agency Advisory Committee

W.L. Berry	Government Relations, Eastern Exploration and Production Operations, Shell Oil Company, New Orleans, La.
B.J. Copeland	UNC Sea Grant College Program, Raleigh, N.C.
Dirk Frankenberg	Curriculum in Marine Sciences, UNC-Chapel Hill, Chapel Hill, N.C.
S. Henri Johnson	N.C. Fisheries Association, New Bern, N.C.
Charles Liner	Institute of Government, UNC-Chapel Hill, Chapel Hill, N.C.
Todd Miller	N.C. Coastal Federation, Newport, N.C.
Bruce Muga	Department of Civil Engineering, Duke University, Durham, N.C.
Brad Rice	Pamlico County Board of Commissioners, Arapahoe, N.C.
Angela Waldorf	N.C. Petroleum Council, Raleigh, N.C.

### State Agency Advisors

Steve Conrad	Division of Land Resources, NRCD
T. Stuart Critcher	Wildlife Resources Commission
Bill Flournoy	Natural Resources Planning and Assessment, NRCD
Joe Henderson, J.K. Sherron	State Property Office, Department of Administration
Derr Leonhardt	Industrial Development, Department of Commerce
Dan McLawhorn, Andy Giles, Allen Jernigan, Frank Crawley	Department of Justice
David Owens	Office of Coastal Management, NRCD

William Ross

Office of Legal Affairs, NRCD

Terry Sholar

Division of Marine Fisheries, NRCD

Eric Vernon

Office of Marine Affairs, Department of  
Administration

R. Paul Wilms,  
Perry Nelson

Division of Environmental Management, NRCD

## APPENDIX B

### Acronyms Used in the Text

AEC	Area of Environmental Concern
CAMA	N.C. Coastal Area Management Act
CFR	Code of Federal Regulations
COS	N.C. Council of State
COST	Continental Offshore Stratigraphic Test
DOA	N.C. Department of Administration
EIS	Environmental Impact Statement
EMC	Environmental Management Commission
MFC	Marine Fisheries Commission
MMS	Minerals Management Service
NAAQS	National Ambient Air Quality Standards
NCAC	North Carolina Administrative Code
N.C.G.S., N.C. Gen. Stat.	North Carolina General Statutes
NEPA	National Environmental Policy Act
NPDES	National Pollutant Discharge Elimination System
NRCD, DNRCD	N.C. Department of Natural Resources and Community Development
OCM	N.C. Office of Coastal Management
OCS	Outer Continental Shelf
OSHA	Occupational Safety and Health Act of 1970
OSHANC	Occupational Safety and Health Act of North Carolina
SEPA	State Environmental Policy Act (North Carolina)
U.S.C.	United States Code

## APPENDIX C

### Petroleum Prospects in the Coastal Plain of North Carolina

#### 1. Formation of Petroleum

Although the processes by which oil and gas form and accumulate are generally known, there is still much that is poorly understood. Most oil and gas appears to have its origin in the coastal and shallow marine environments of estuaries, lagoons, and continental shelves and slopes.<sup>1</sup> In these biologically productive areas, there is a slow, steady rain of organic matter to the bottom. Where the sediments are sandy and well-aerated, microbial activity usually decomposes this organic matter completely before it can become deeply buried. In finer silts and clays, however, new deposition may cut off oxygen diffusion from overlying waters before degradation of the hydrocarbons is complete. As the sediments become buried under progressively thicker overlying sediments, temperature and pressure increase, and the entrapped organic matter undergoes a series of chemical transformations. First, the smaller hydrocarbon molecules recombine to form a variety of insoluble, complex molecules collectively known as kerogen. With increasing temperature, the kerogen begins to degrade, releasing first liquid petroleum compounds and then progressively lighter hydrocarbons until, in the final stages under conditions of very high temperature and pressure, only methane and a carbon residue remain. Because temperature and depth are directly related, in any one area the hydrocarbons generated from a source bed will be a general function of depth (Figure C-1). Time is also a factor, for like most chemical reactions, the generation of hydrocarbons proceeds faster at higher temperatures. Petroleum formation may occur within 5-10 million years of source bed deposition, or may take as long as 100 million years or more.

Petroleum is never extracted directly from the rock in which it is generated, for the source beds, formed from silts and clays, are not sufficiently permeable to allow the petroleum present to flow to a well with the speed necessary to make extraction economical. Instead, the petroleum engineer relies on the processes of migration and accumulation to produce petroleum reservoirs of commercial proportions. The processes causing expulsion of hydrocarbons from source beds are poorly understood, but a major mechanism appears to be the pressure built up during generation of the petroleum itself. Expelled from the source beds into more permeable sandstones and carbonates, the hydrocarbons tend to migrate upwards, driven by their buoyancy relative to the water filling the pore spaces of the surrounding rocks. This migration continues until stopped by a barrier or trap. If the trap is sufficiently large and of the right configuration, and if the rock beneath the trap (known

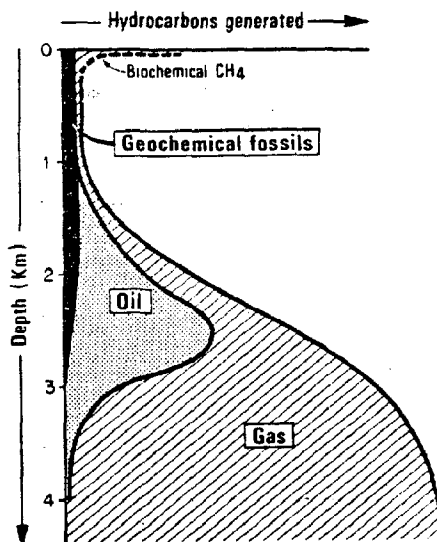
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<sup>1</sup>Much of the following discussion is drawn from B.P. Tissot and D.H. Welte, Petroleum Formation and Occurrence (Berlin: Springer-Verlag, 1978), and the reader is referred to that work for an excellent and detailed account of this subject.

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Figure C-1

General Scheme of Hydrocarbon Formation as a Function  
of Burial of the Source Rock



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After B.P. Tissot and D.H. Welte, Petroleum Formation and Occurrence (Berlin: Springer-Verlag, 1978).

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as the reservoir rock) is sufficiently porous and permeable to hold a large volume of petroleum, a substantial amount of petroleum may accumulate, creating a reservoir.

A trap occurs where rock of low permeability to hydrocarbons comes to lie above rock of higher permeability. Traps are commonly of two types. Structural traps (Figure C-2) are formed by the folding or faulting of rock layers, while stratigraphic traps (Figure C-3) are caused by either a nonporous formation sealing off the top edge of a reservoir bed or by a change in porosity and permeability within the reservoir bed itself.<sup>2</sup> Most of the petroleum reservoirs found to date have occurred underneath structural traps, but this may partly be due to the fact that structural traps are easier than stratigraphic traps to identify with existing exploration technology.

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<sup>2</sup>Petroleum Extension Service, Fundamentals of Petroleum, 2nd ed. (Austin, Texas: Petroleum Extension Service, University of Texas at Austin, 1981), p. 15.

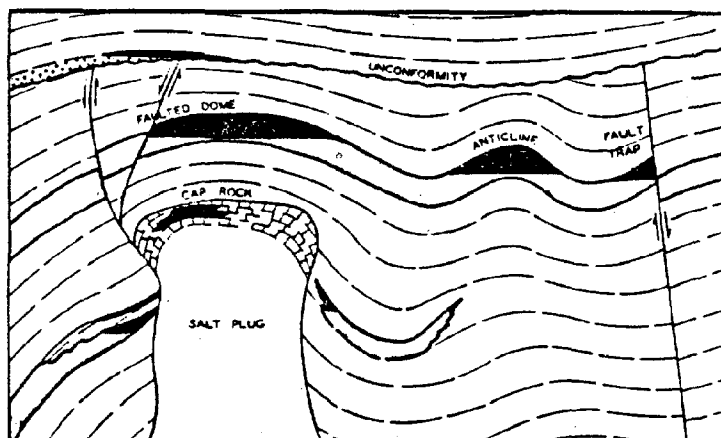


Figure C-2. Common Types of Structural Traps. From Petroleum Extension Service, Fundamentals of Petroleum, 2d ed. (Austin, TX: PES, Univ. of Texas at Austin, 1981), p. 12.

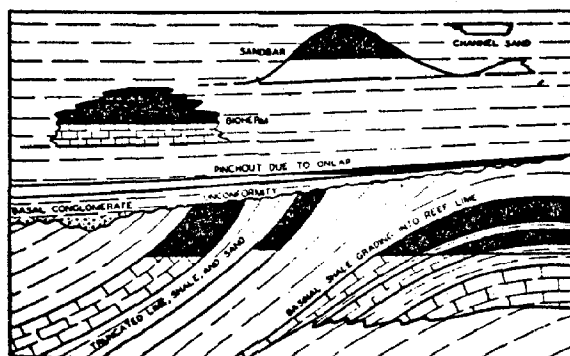


Figure C-3. Common Types of Stratigraphic Traps. From Petroleum Extension Service, Fundamentals of Petroleum, 2d ed. (Austin, TX.: PES, Univ. of Texas at Austin, 1981), p. 15.

Miller and others<sup>3</sup> list several criteria that petroleum-producing areas must possess: (1) an adequate thickness of sedimentary rocks; (2) source beds containing considerable dispersed organic matter; (3) a suitable environment for the maturation of organic matter; (4) porous and permeable reservoir beds; (5) hydrodynamic conditions favorable for both early migration and ultimate entrapment of oil and gas; (6) a favorable thermal history; (7) adequate trapping mechanisms; and (8) suitable timing of petroleum generation and migration in relation to the development of traps. The key question is, to what extent are these conditions present, or have have been present, in eastern North Carolina?

## 2. Geology of the North Carolina Coastal Plain

The North Carolina coastal plain is part of a much larger system of Mesozoic and Cenozoic sediments that stretch from Florida to Newfoundland. Within the state the sediments form a wedge-shaped mass, thickening eastward from a feather edge along the fall line to 10,000 feet at Cape Hatteras and to more than 35,000 feet in the Carolina Trough on the Outer Continental Shelf.<sup>4</sup> The basement beneath these sediments is comprised primarily of igneous and metamorphic rocks of Precambrian and Paleozoic age, similar to those that crop out in the Piedmont. The basement surface appears to slope gently toward the sea at slopes ranging from 10 feet/mile inland to as much as 120 feet/mile near the ocean. For the most part this slope is perpendicular to the Appalachians. In southeastern North Carolina, however, there occurs a distinctive structure known as the Cape Fear Arch, a broad, southeast plunging nose in the basement surface. The arch and the general slope to the east together account for the varying thicknesses of sediments overlying the basement surface, from 1100 feet near Cape Fear, to 5000 feet at Cape Lookout and 10,000 feet at Cape Hatteras.<sup>5</sup>

These overlying sediments crop out in broad belts that roughly parallel the coastline. The oldest occur farthest west and are buried progressively

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<sup>3</sup>B.M. Miller, H.L. Thompsen, G.L. Dolton, and others, Geological Estimates of Undiscovered Recoverable Oil and Gas Resources in the U.S., Geological Survey Circular 725 (Reston, Va.: U.S. Geological Survey, 1975), p. 17.

<sup>4</sup>Stephen G. Conrad, P. Albert Carpenter, III, and William F. Wilson, "Physiography, Geology, and Mineral Resources," Ch. 5 in James W. Clay, Douglas M. Orr, Jr., and Alfred W. Stuart, eds., North Carolina Atlas (Chapel Hill: University of North Carolina Press, 1975), p. 117; Jeffrey L. Deis, Frederick N. Kurz, and Elizabeth O. Porter, South Atlantic Summary Report 2, U.S. Geological Survey Open-File Report 82-15 (Reston, Va.: Minerals Management Service, 1982), p. 31.

<sup>5</sup>John C. Maher, Geologic Framework and Petroleum Potential of the Atlantic Coastal Plain and Continental Shelf, Geological Survey Professional Paper 659 (Washington, D.C.: U.S. Geological Survey, 1971), p. 22.

deeper as one moves east (Figure C-4). The sedimentary sequence is reviewed in detail in several publications<sup>6</sup> and will not be discussed at length here. For the most part, the sedimentary rocks exposed onshore are continental and near-shore marine clastics, with occasional interspersed beds of marl and lignite.<sup>7</sup> As one moves east, the sedimentary sequence becomes thicker, younger, and increasingly marine in origin. Of all North Carolina wells drilled to date, the thickest and most completely marine section was found at Cape Hatteras, where all but the basal 700 feet of the 9900 feet of sedimentary rock drilled through is essentially marine in origin. The bulk of the section was deposited between the Lower Cretaceous and the Miocene (approximately 100 to 10 million years ago), and consists of roughly 40 percent sandstone, 30 percent carbonate rock (limestone, dolomite, and others), and 30 percent shale.<sup>8</sup>

### 3. Petroleum Potential of Eastern North Carolina

To date, there have been no finds of oil or gas of commercial size in the U.S. Atlantic coastal plain. The potential for oil or gas in eastern North Carolina has been a subject of disagreement among professional geologists for years. Large areas of the coastal plain remain unexplored, and the possibility exists that commercial reservoirs of petroleum may yet be discovered.

Coastal North Carolina does possess some of the prerequisites for petroleum accumulations. Source beds for hydrocarbons, generally regarded to be marine shales, marls, and limestones in roughly that order of importance, are scattered throughout the sedimentary sequence beneath the coastal plain; at Cape Hatteras they make up more than half of the sequence.<sup>9</sup> Moreover, asphalt has been found at varying depths in several wells in the outer plain.<sup>10</sup> Inland the sedimentary rocks, more continental in origin, are more likely to be sources of dry gas than of oil. Reservoir rocks (primarily sandstones and limestones) are thick and numerous beneath the Atlantic Coastal Plain, and several thick sandstone and limestone beds with good reservoir characteristics were found at the Cape Hatteras well.

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<sup>6</sup>See Maher, Geologic Framework, and Philip M. Brown, James A. Miller, and Frederick M. Swain, Structural and Stratigraphic Framework, and Spatial Distribution of Permeability of the Atlantic Coastal Plain, North Carolina to New York, Geological Survey Professional Paper 796 (Washington, D.C.: U.S. Geological Survey, 1972).

<sup>7</sup>Maher, Geologic Framework, pp. 26-27.

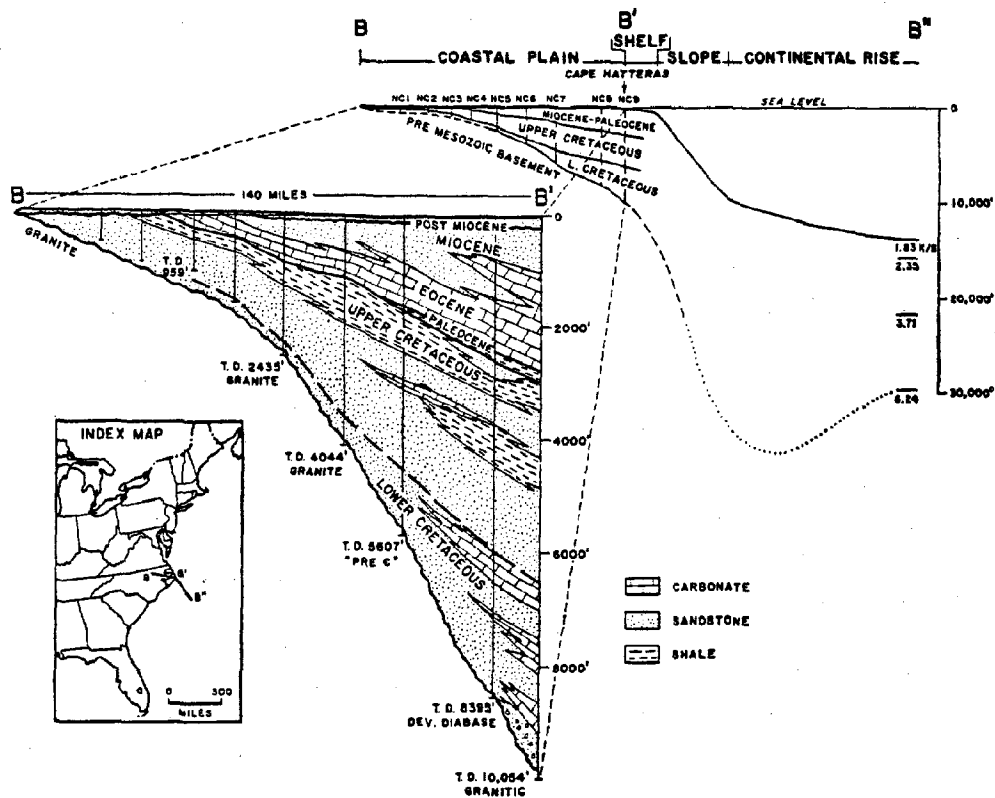
<sup>8</sup>J. Spivak and O.B. Shelburne, "Future Hydrocarbon Potential of Atlantic Coastal Province," pp. 1295-1310 in Ira H. Cram, ed., Future Petroleum Provinces of the United States -- Their Geology and Potential, Memoir 15, 2 vols. (Tulsa: American Association of Petroleum Geologists, 1971), Vol. 2, p. 1306.

<sup>9</sup>Maher, Geologic Framework, p. 58.

<sup>10</sup>Philip M. Brown et al., Structural and Stratigraphic Framework, Cross Section Z" - Z"'.

Figure C-4

Structural Cross-Section Across the Coastal Plain  
to the Continental Rise at Cape Hatteras, North Carolina



From John C. Maher, Geologic Framework and Petroleum Potential of the Atlantic Coastal Plain and Continental Shelf, Prof. Paper 659 (Washington, D.C.: U.S. Geological Survey, 1971).

A variety of potential traps exist in coastal plain sediments. Sealing beds, usually of clay, shale, or salt, are a necessary ingredient of most petroleum traps, and beds of clay and shale are relatively common in the North Carolina sedimentary sequence.<sup>11</sup> Though the coastal province has been very quiet tectonically during the deposition of these sediments, studies continue

<sup>11</sup>Maher, Geologic Framework, pp. 61-62.

to find many small faults and anticlinal structures that could serve as petroleum traps. Stratigraphic traps, such as pinch-outs, channel fills, offshore bars, and buried reefs, are also thought to occur in scattered locations.

It is the question of thermal maturity that casts doubt on the petroleum generating potential of eastern North Carolina sediments. As explained earlier, source rocks require a prolonged period at sufficient temperature (50° - 100°C) for the kerogen matrix to generate liquid and gaseous hydrocarbons. The lower the temperature, the longer the period needed. Although the geothermal gradient varies from place to place, it is thought that 10,000 feet is an approximate minimum depth in the coastal plain for the necessary combination of temperature and time to produce petroleum. Work elsewhere along the Atlantic coast tends to support this view. Six exploratory wells drilled in the Southeast Georgia Embayment on leases sold in OCS Sale 43 were all dry. The deepest strata penetrated by the COST well drilled in the Embayment, at a depth of approximately 10,800 feet, seem to be thermally mature but are continental deposits and therefore inferior as a source of petroleum.<sup>12</sup> Several younger, shallower strata exhibit good to very good source-generating potential, but appear to be geothermally immature.<sup>13</sup> Modelling studies by Angevine and Turcotte suggest that optimum conditions for petroleum generation along the Atlantic continental margin are found at depths of 20,000 - 26,000 feet.<sup>14</sup>

The most likely location of source beds that have been subjected to the right combination of time and temperature is the far eastern edge of the coastal plain, where sediment thickness of 9,000-10,000 feet and more occur. Elsewhere in the coastal plain it seems unlikely that potential source beds have reached thermal maturity. This is not to say, however, that the potential for finding petroleum in eastern North Carolina is equally low. In some instances oil and gas are known to have migrated many miles from their source beds to the reservoirs from which they were ultimately produced. Especially considering the general dip of coastal strata to the east, it is quite possible that petroleum formed at greater depths in the Outer Continental Shelf has migrated up to the west and been trapped in coastal plain sediments. Only continued exploratory drilling can confirm or deny this possibility.

While most petroleum exploration in North Carolina has historically focused on the coastal plain, other locations in and near the state are receiving interest. Further offshore beyond the three-mile limit, the sedimentary sequence is considerably thicker, and the possibility of thermally mature source beds is much greater. This, combined with the presence of faults, salt domes, buried reefs, and other potential traps, has made the

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<sup>12</sup>Deis, Kurz, and Porter, South Atlantic Summary Report 2, p. 31.

<sup>13</sup> Ibid.; Stephen W. Brown, Paul J. Cernock, and Joseph A. Haykus, "Regional Hydrocarbon Source-Rock Evaluation of Atlantic Coastal Plain Adjacent to Georgia Embayment" (abstract), Am. Assoc. Pet. Geol. Bull. 63(3):425-426, 1979.

<sup>14</sup>Charles Angevine and D.I. Turcotte, "Thermal Evolution of Sedimentary Basins Along Atlantic Continental Margins of United States" (abstract), Am. Assoc. Pet. Geol. Bull. 64(5):670, 1980.

North Carolina OCS one of the most promising new offshore areas for petroleum development. Exploratory drilling in this region, expected to begin soon, may throw more light on the potential for petroleum in North Carolina waters as well.

Other areas that have attracted interest are the eastern overthrust belt in western North Carolina and the Triassic sediments found in downfaulted basins in the Piedmont.

## APPENDIX D

### Environmental Impacts of Petroleum Exploration and Development in North Carolina Submerged Lands

The impacts of oil and gas development in coastal North Carolina will vary because of the diversity of coastal environments and the different technologies used in these environments. The following sections describe each of the major activities that take place during petroleum exploration and development, the range of options for accomplishing each, and the potential impact of each approach. These accounts are designed to be introductory rather than exhaustive and should provide the reader with an idea of guidelines and regulations that might be imposed to control environmental impacts at socially acceptable levels.

For more information the reader is referred to the reference footnotes of this chapter and to a number of excellent studies that have been published over the last decade. These include general reports on coastal and offshore petroleum development<sup>1</sup> and reports that focus on specific phases of such development (particularly pipelines).<sup>2</sup> Two major studies in the Gulf have

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<sup>1</sup>William L. Longley, Rodney Jackson, and Bruce Snyder, Managing Oil and Gas Activities in Coastal Environments: Refuge Manual, Publication FWS/OBS-81/22 (Washington, D.C.: Office of Biological Services, U.S. Fish and Wildlife Service, 1981), 451 pp.; William L. Longley, Rodney Jackson and Bruce Snyder, Managing Oil and Gas Activities in Coastal Environments, Publication FWS/OBS-78/54 (Washington, D.C.: Office of Biological Services, U.S. Fish and Wildlife Service, 1978), 66 pp.; David J. Brower, William D. McElyea, David R. Godschalk, and Nancy D. Lofaro, Outer Continental Shelf Development and the North Carolina Coast: A Guide for Local Planners, CEIP Report No. 5 (Raleigh, N.C.: N.C. Department of Natural Resources and Community Development, 1981), 256 pp.; John Clark and Charles Terrell, Environmental Planning for Offshore Oil and Gas, Volume III: Effects on Living Resources and Habitats, Publication FWS/OBS-77/14 (Washington, D.C.: Office of Biological Services, U.S. Fish and Wildlife Service, 1978), 220 pp.; W.H. Conner, J.H. Stone, L.M. Bahr and others, Oil and Gas Use Characterization, Impacts and Guidelines, Sea Grant Publication LSU-T-76-006 (Baton Rouge, La.: Sea Grant Program, Louisiana State University, 1976), 148 pp.; New England River Basins Commission, Factbook (Boston, Mass.: New England River Basins Commission, 1976), various pagings.

<sup>2</sup>F. Yates Sorrell, Richard R. Johnson, Charles D. Wyman and others, Oil and Gas Pipelines in Coastal North Carolina: Impacts and Routing Considerations, CEIP Report No. 33 (Raleigh, N.C.: N.C. Department of Natural Resources and Community Development, 1982), 266 pp.; Ann W. Gowen and Michael J. Goetz, Pipeline Landfalls: A Handbook of Impact Management Techniques (Cincinnati, Ohio: U.S. Environmental Protection Agency, 1981), 201 pp.; Ann W. Gowen, M.J. Goetz, and I.M. Waitsman, Choosing Offshore Pipeline Routes:

attempted to assess the cumulative ecological effects of offshore development.<sup>3</sup> The Environmental Impact Statements and other environmental documents issued by the Minerals Management Service for OCS activities contain a wealth of data relevant to North Carolina waters, particularly those seaward of the barrier islands. Fewer impact statements for shallow water activities have been issued; one useful series is the set of three EIS's prepared by the Corps of Engineers for Mobil's exploration and development of the Lower Mobile Bay Gas Field in Alabama.<sup>4</sup>

## 1. Geophysical Exploration

Commercially exploitable petroleum deposits are formed when organic matter is heated to produce oil or gas and these products are collected and concentrated by geological structures called "traps." Looking for such trapping structures is the purpose of geophysical exploration.

Modern geophysical exploration uses sound waves to probe beneath the earth's surface. As these sound waves travel through sediment and rock, a

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Problems and Solutions, Report No. EPA-600/7-80-114 (Cincinnati, Ohio: U.S. Environmental Protection Agency, 1980), 92 pp.; Robert J. Golden, Jr., Kenneth Gallagher, Norbert P. Psuty and others, OCS Natural Gas Pipelines: An Analysis of Routing Issues (New Brunswick, N.J.: Center for Coastal and Environmental Studies, Rutgers--The State University of New Jersey, 1980), 432 pp.; A.H. Rooney-Char and R.P. Ayers, Offshore Pipeline Corridors and Landfalls in Coastal Virginia, Special Report in Applied Marine Science and Ocean Engineering No. 190, 2 vols. (Gloucester Point, Va.: Virginia Institute of Marine Science, 1978); Charles A. Willingham, Barney W. Cornaby, and David G. Engstrom, A Study of Selected Coastal Zone Ecosystems in the Gulf of Mexico in Relation to Gas Pipelining Activities (Columbus, Ohio: Battelle Columbus Laboratories, 1975), various pagings; John T. McGinnis, Robert A. Ewing, Charles A. Willingham and others, Environmental Aspects of Gas Pipeline Operations in the Louisiana Coastal Marshes (Columbus, Ohio: Battelle Columbus Laboratories, 1972), various pagings.

<sup>3</sup>Brian S. Middleditch, ed., Environmental Effects of Offshore Oil Production: The Buccaneer Gas and Oil Field Study, Marine Science Vol. 14 (New York: Plenum Press, 1981), 446 pp.; C.H. Ward, M.E. Bender, and D.J. Reish, eds., "The Offshore Ecology Investigation: Effects of Oil Drilling and Production in a Coastal Environment," Rice University Studies 65 (4-5): 1-589, 1979.

<sup>4</sup>U.S. Army Corps of Engineers (Mobile District), Final Environmental Statement, Permit Application by Mobil Oil Corporation, Exploratory Oil Well, Mobile Bay, Alabama (Mobile, Ala.: U.S. Army Corps of Engineers, 1976), various pagings; U.S. Army Corps of Engineers (Mobile District), Final Environmental Impact Statement for Four Exploratory/Appraisal Hydrocarbon Wells, Mobile Bay, Alabama (Mobile, Ala.: U.S. Army Corps of Engineers, 1980), various pagings; U.S. Army Corps of Engineers (Mobile District), Production of Natural Gas from the Lower Mobile Bay Field, Alabama, Final Environmental Impact Statement (Mobile, Ala.: U.S. Army Corps of Engineers, 1982), various pagings.

small percentage of their energy is reflected back toward the surface after encountering changes in rock and/or sediment type. Recording the highly amplified echos from these reflections provides remotely sensed data on the shape, depth, and geometry of the reflecting surfaces.<sup>5</sup> Surfaces that have been deformed to create downward facing basins are known to sometimes trap oil and gas formed around or under them. While drilling is the best way to determine subsurface geology and the presence of oil or gas, it is also expensive, hence the interest in finding the traps in advance of drilling.

Geophysical exploration of rocks under the seafloor is done by vessels that tow long cables carrying numerous underwater microphones and a large sound source. Early technology used explosions for the sound source, but now release of compressed air (air gun) or an electrical discharge (sparker) is used.<sup>6</sup> The noise from this source travels over many paths to the microphones. The paths of interest for geophysical exploration pass into the seafloor, off rock surfaces beneath it, and back up through the seafloor to the microphones. These echoes are recorded and analyzed for evidence of the shape of subbottom rock surfaces. Modern geophysical survey ships record 96 or more different sound frequencies at one time, and the expense of analyzing the data can make a mile of modern multichannel subbottom profiling cost as much to produce as a mile of superhighway. The environmental impact of such activity is negligible. The passage of the vessel and the possibility that a few marine animals may be stunned or killed by the air bubble or spark are the only general problems. Possibilities for accident, loss of cable, etc., exist but are small for a competently run operation.

Unfortunately seismic subbottom profiling from ships is not always possible or practical in nearshore areas such as those in North Carolina. Not only does shallow water limit areas where deep draft (ca. 12 feet) geophysical survey vessels can operate, but enclosed and crowded waters also make it impossible to deploy long (ca. 1/2 mile) towed instrument arrays. In addition, sound sources that are effective in deep water produce bottom echoes in shallow water that can confound data retrieval. Thus other geophysical exploration techniques are needed in shallow water and salt marsh habitats. The technique most often used on the Gulf of Mexico coastline is a modification of terrestrial procedures that use explosives. In this operation a shallow hole is drilled into the marsh, an explosive charge is placed within, recording microphones are positioned along "shot" lines running away from the explosion site, and, when everything is in place, the charge is detonated to produce sound waves that pass downward to reflect off subsurface features.<sup>7</sup>

The environmental impact of this procedure can be substantial. The explosion obviously creates noise, air pollution and a hole, but pre-explosion construction may also have lasting impact on coastal wetlands. In current practice the drill rig is positioned on "rig mats" made of removable boards, but associated access roads, levees, cable laying, and human presence may have

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<sup>5</sup>J. Kennett, Marine Geology (Englewood Cliffs, N.J.: Prentice Hall, Inc. 1982), xv + 813 pp.

<sup>6</sup>Ibid.

<sup>7</sup>Longley et al., Managing Oil and Gas Activities: Refuge Manual.

substantial impacts on salt marsh habitats. In coastal marshes much of the human access and cable laying is by marsh buggies. These vehicles operate on either large, low-pressure rubber tires or tank-like treads. Although these devices spread the vehicle's weight over a large surface area, marsh buggies still produce ruts on most marsh surfaces. These ruts enhance water movement over the marsh, often producing luxuriant growth of marsh grass for many years after vehicle passage. Marsh plants are extremely susceptible to changes in marsh height or drainage characteristics, so all construction activities that alter these features of the environment can be expected to have a significant impact. Increasing the level of the sediment surface or decreasing drainage may render the environment intolerable to marsh plants or any other vegetation.<sup>8</sup> On the other hand, decreasing sediment height or increasing drainage usually increases growth and vigor of salt marsh grasses (*Spartina* spp.), and may actually increase the productivity of the marsh ecosystem. Which, if either, of these impacts results from construction for explosion-based geophysical exploration will depend on the specific construction procedures used at specific sites and cannot be described in detail in advance.

## 2. Dredging and Filling

Coastal oil and gas development may require dredging and/or filling in conjunction with three separate operations: provision of access to the well site, preparation of the well site itself, and pipeline installation. The standard drilling structure in coastal waters less than 20 feet deep (most of North Carolina's inshore waters) is the submersible drilling barge. A typical barge measures 50 by 180 feet and for transport generally requires a channel 70 or more feet wide and 8-10 feet deep. Where water depths are shallower, dredging of an access canal will be necessary. At the well site itself, a larger area known as the slip must be excavated in shallow waters to accommodate not only the drilling barge but also the supply barges and barges that hold the drilling muds. When the barge arrives on site, the ballast tanks are flooded and the barge sinks until its hull rests on the bottom, providing a stable platform for drilling operations. In water depths over 10 feet, a shell pad may be laid first to provide a sufficiently shallow bottom for the barge to rest upon.

Access to marsh drill sites may be achieved either by dredging an access canal through the marsh, or by building a road out from dry land for transport of a land rig. The choice will depend on the location of the site relative to existing channels and roads, the ability of the marsh soil to support heavy equipment, the decisions of regulatory agencies, and other factors. Where a road is to be built, standard practice has been to use marsh soils adjacent to the roadway for the road base, and then to construct a board road on top, capped with earth, sand, or shell where the road is to be used over a long period. In some cases, the boards may be placed directly on the original marsh surface, or the road may be built entirely with fill from outside the marsh area. At the well site, draglines construct a levee (approximately 400 feet square) around the site from marsh soils. The rig is placed on a board

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<sup>8</sup>D.S. Ranwell, Ecology of Salt Marshes and Sand Dunes (London: Chapman and Hall, 1971), xiv + 258 pp.

rig mat laid directly on the marsh surface. Steel mud pits are now favored over pits excavated in the marsh itself.

For reasons of safety and stability, most utility lines (including oil and gas lines) crossing marshes and coastal waters are buried beneath the mud surface. The practice of the Minerals Management Service in the Gulf offshore waters has been to require burial of pipelines more than 8 inches (22 cm) in diameter; smaller lines may or may not be buried, depending on the preferences of the operator and conditions specific to the area. In open water, burial is accomplished by excavating a trench either before the line is laid, next to the laid line, or from beneath the laid line; the line is then placed in the trench, except in the latter case where it settles into the trench naturally. The trench is backfilled or left to backfill naturally. In marsh areas, a trench is excavated first, the pipeline is constructed at one end and floated into the trench as the line is constructed, and the floats then cut away and the trench backfilled over the settled pipeline.

A great deal of research on the impacts of dredging and filling in estuarine systems has been conducted in recent years. Nevertheless, our understanding of this subject is far from complete, and predictions of specific impacts are not yet possible with much assurance. The effects of dredging have been the subject of several recent reviews<sup>9</sup> and of an extensive research effort (the Dredged Material Research Program) of the Corps of Engineers. The impacts of oil rig access canals and pipeline canals have been specifically addressed by a number of authors.<sup>10</sup>

The major ecological impacts of dredging and filling in estuarine systems can be grouped into four categories:

- alteration or destruction of habitat where the canal is dredged and where the spoil or fill is placed;

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<sup>9</sup>Sam A. Johnston, Jr., "Estuarine Dredge and Fill Activities: A Review of Impacts," Environmental Management 5(5):427-440, 1981; Kenneth O. Allen and Joe W. Hardy, Impacts of Navigational Dredging on Fish and Wildlife: A Literature Review, Publication FWS/OBS-80/07 (Washington, D.C.: Office of Biological Services, U.S. Fish and Wildlife Service, 1980); James W. Morton, Ecological Effects of Dredging and Dredge Spoil Disposal: A Literature Review, Technical Paper No. 94 (Washington, D.C.: U.S. Fish and Wildlife Service, 1977), 33pp.

<sup>10</sup>See, e.g., Longley et al., Managing Oil and Gas Activities: Refuge Manual; Conner et al., Oil and Gas Use Characterization; McGinnis et al., Environmental Aspects of Gas Pipeline Operations; N.J. Craig, R.E. Turner, and J.W. Day, Jr., "Land Loss in Coastal Louisiana," pp. 227-254 in: J.W. Day, Jr., D.D. Culley, Jr., R.E. Turner, and A.J. Mumphrey, Jr., eds., Proceedings of the Third Coastal Marsh and Estuary Management Symposium (Baton Rouge, La.: Louisiana State University Division of Continuing Education, 1979); Gerald Adkins and Philip Bowman, A Study of the Fauna in Dredged Canals of Coastal Louisiana, Technical Bulletin No. 18 (New Orleans, La.: Louisiana Wildlife and Fisheries Commission, 1976), 70pp.

- increases in suspended sediment and its various effects on the water column;
- sedimentation; and
- changes in estuarine and marshland hydrology.

These effects will have secondary consequences for commercial and recreational fishermen and other users of estuarine waters. In addition, dredging and filling activities may disturb archaeological and historic artifacts.

The most immediate impact of dredging and filling in estuaries is the destruction of benthic organisms where sediments are dredged and spoil or fill placed. Recolonization tends to be highly variable in time and species composition, and its nature appears to depend on substrate characteristics, the biology of the plants and animals involved, and a variety of other factors. Generally the more naturally variable the environment, the better adapted the biota is to unstable conditions and disturbances like dredging and filling.<sup>11</sup> In estuaries, recolonization is often rapid and original biomass may be reached within a few weeks, though colonizers tend to be opportunistic species and species diversity remains depressed for some time.<sup>12</sup>

Laboratory and field studies have found considerable variation in the abilities of benthic animals to escape from under a blanket of sediment. Sessile animals, such as barnacles, oysters, and mussels, are destroyed, as are most epifaunal forms. Many of the infauna have demonstrated abilities to migrate upward through dredged material in the lab, but few field studies have found any contribution to recolonization of spoil deposits from vertical migration.<sup>13</sup> Sedimentation from settling materials or from spoil redistributed by currents may smother oysters or render substrate unsuitable for spat attachment.<sup>14</sup> On the other hand, shell platforms placed at drilling sites may provide good additional substrate for the development of oyster populations.

The effects of canal or road construction through marshland will generally be to replace highly productive marsh with less productive open water (canal) or upland (spoil banks), or with nonproductive road. The amount of

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<sup>11</sup>Nina D. Hirsch, Louis H. DiSalvo, and Richard Peddicord, Effects of Dredging and Disposal on Aquatic Organisms, DMRP Technical Report DS-78-5 (Vicksburg, Miss.: U.S. Army Engineer Waterways Experiment Station, 1978), p. 17.

<sup>12</sup>Allen and Hardy, Impacts of Navigational Dredging, p. 17.

<sup>13</sup>Hirsch et al., Effects of Dredging, pp. 15-17.

<sup>14</sup> Curt D. Rose, "Mortality of Market-Sized Oysters (*Crassostrea virginica*) in the Vicinity of a Dredging Operation," Chesapeake Science 14:135-138, 1973; Ronald Fiore, "Oyster Reefs," pp. 73-87 in: Raymond Alden, David Brower, B.J. Copeland and others, Ecological Determinants of Coastal Area Management, Vol. II: Appendices, Sea Grant Publication UNC-SG-76-05 (Raleigh, N.C.: UNC Sea Grant College Program, 1976).

marsh whose productivity is directly reduced or eliminated by canal construction is generally several times the canal width, due to spoil placement, traffic and other construction activities. Marsh destruction does not end with canal construction, however. Experience in the Gulf shows that, over time, access and pipeline canals may enlarge dramatically through bank erosion. Recent work also suggests that man-made canals may be responsible for the major portion of coastal Louisiana's alarming rate of land loss of 102 km<sup>2</sup>/year, probably through interruption of local and regional hydrologic regimes.<sup>15</sup> A number of design measures have been suggested to mitigate these impacts.<sup>16</sup>

Research has catalogued a range of potential environmental effects that may be caused by sediments suspended during dredging and filling operations. These include: a decrease in light penetration, resulting in reduced photosynthetic activity; various physical and pathological effects on fish and invertebrates, particularly gill function; the release of nutrients and toxic substances (both natural and man-made) from disturbed sediments; interference with animal migrations; and reduction in dissolved oxygen levels. However, many of these same studies show that turbidity levels generated by dredging are comparable to those created by trawling and natural storm events, and that for the most part the impacts listed above are observed only in localized instances.<sup>17</sup>

Canals and adjacent spoil banks (when deposited linearly) may disrupt estuarine circulation, thereby altering patterns of salinity, temperature, dissolved oxygen, sediment movement, and water exchange. A classic example of these effects is that of South Bay, near Brownsville, Texas. Dredged material from the Brownsville ship channel was placed along the north end of South Bay, closing it off except for a narrow, shallow inlet. As a result, Boca Chica Pass, South Bay's other inlet, filled in, circulation in South Bay became virtually non-existent, the average depth decreased from 1.2 to 0.4 m, the oyster population was destroyed, and fish and other invertebrate populations declined.<sup>18</sup>

Marshland hydrology will also be altered by canal or pipeline ditch construction, with potentially deleterious impacts on marsh productivity. Results may include greater saltwater intrusion into the marsh; diversion of freshwater upland runoff from the marsh surface, thereby draining the marsh and depriving it of nutrient and sediment input; and impoundment of water on

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<sup>15</sup>William W. Scaife, R. Eugene Turner, and Robert Costanza, "Coastal Louisiana Recent Land Loss and Canal Impacts," Environmental Management, in press.

<sup>16</sup>Scaife et al., "Recent Land Loss"; Craig et al., "Land Loss in Coastal Louisiana"; Longley et al., Managing Oil and Gas Activities: Refuge Manual.

<sup>17</sup>Sorrell et al., Oil and Gas Pipelines in Coastal North Carolina, pp. 89-91.

<sup>18</sup>Joseph P. Breuer, "An Ecological Survey of the Lower Laguna Madre of Texas, 1953-1959," Publ. Inst. Mar. Sci. (U. Texas) 8:143-183, 1962.

the marsh surface by spoil levees.<sup>19</sup> Such changes may lead to significant shifts in marshland vegetation and animal distribution patterns. In recent years there has been a trend in the Gulf states towards requiring the back-filling of pipeline canals, thereby substantially reducing these impacts.

### 3. The Presence of Structures and Boats

The presence of drilling rigs, platforms, and construction and supply vessels may affect navigation and shipping, fishing activities, visual quality, and other uses of the state's territorial waters.

The major impact on marine shipping and navigation will be the presence of exploration rigs and drilling and production platforms. Navigational or operational errors in the vicinity of platforms may result in collisions. The danger is highest early in field development, before vessel traffic adjusts to the presence of these structures. In the Gulf, where currently over 80,000 ships each year cross waters containing 3700 structures, 12 major collisions with OCS structures occurred in the period 1963-1977, including one involving fatalities.<sup>20</sup> The Coast Guard has established a uniform system of aids to navigation for identifying offshore structures and minimizing such collisions.<sup>21</sup>

Other hazards include the increased traffic generated by supply boats, crew boats and other oil-related vessels which often move across customary lanes of travel. Geophysical survey vessels towing instrument arrays and pipeline construction and barge barges have limited mobility and may disrupt other marine activities and vessels. Fishing boats also have limited mobility when towing gear and are sometimes placed on automatic pilot to free up an additional crewman for handling gear; during these times, increased vessel traffic will create an additional hazard to them. Stipulations attached to OCS Sale 42 on Georges Bank and the proposed California lease sale off Santa Barbara County require oil and gas operators to train vessel captains and platform- and shore-based supervisors in commercial fishing methods; whether such training is effective in reducing conflicts is an open question. A related hazard, particularly to commercial fishermen, is the trash and debris sometimes lost or dumped overboard by oil and gas operators. The state may wish to consider implementing a program comparable to the federal Fisherman's Contingency Fund or the Louisiana Gear Loss Fund to compensate fishermen for gear damage attributable to oil and gas operations.

Loss of access by commercial fishermen to the area occupied by drilling rigs and platforms is another concern. The amount of spatial exclusion will depend on many factors: type of fishing gear, vessel maneuverability, rig or platform configuration and mooring, weather and sea conditions, legal and

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<sup>19</sup>Sorrell et al., Oil and Gas Pipelines in North Carolina, pp. 142-147.

<sup>20</sup> U.S. Department of Interior, Minerals Management Service, Final Regional Environmental Impact Statement, Gulf of Mexico, 2 Vols. (Metairie, La.: Minerals Management Service, 1983), Vol. 1, p. 402.

<sup>21</sup>33 CFR §67.

safety requirements, and the fisherman's experience and willingness to take risks. The loss of access in areas occupied by subsea structures will be determined by the accuracy with which fishermen can fix the location of the obstruction. Such obstructions will be few in state waters: subsea completions are installed only in the deep waters of the OCS, and pipelines will be buried at most locations within North Carolina's boundaries. These and other potential conflicts between the fishing and oil industries have recently been reviewed by Centaur Associates.<sup>22</sup>

Structures on submerged lands (particularly platforms, but also unburied pipelines) may also act as artificial reefs, providing hard substrate for the development of a biofouling community. Fish are attracted to such structures by the presence of food, shelter, calm water or favorable currents, and the orientation apparently provided by a solid object.<sup>23</sup> Structures in the Gulf are notorious for their good recreational fishing, and some researchers attribute the rise of a major recreational fishery in this region in the last 30 years largely to construction of offshore drilling platforms.<sup>24</sup>

Oil and gas activities and structures may present some conflict with military use of state waters. A number of danger zones have been established in the state's territorial waters; these include target areas, bombing and rocket firing areas, ordnance test areas, and firing ranges. The regulations governing civilian use of these areas may be found at 33 CFR §204. Two areas of restricted navigation, near Cherry Point Marine Corps Air Station and Sunny Point Military Ocean Terminal, have also been established (33 CFR §207). The extent to which oil and gas operations could be conducted within these areas would have to be negotiated with the Department of Defense on a case-by-case basis.

Finally, exploration rigs and drilling and production platforms will in most cases have a negative visual impact. The degree of impact will depend on the quality of the surrounding environment, the distance of the rig or platform from the viewing area, and the number of people to whom the structure is visible.

#### 4. Oil Spills

Oil spills will probably be the environmental impact most feared by North Carolinians during coastal petroleum exploration and development. There is good scientific reason to fear oil spills in coastal waters. Spills can have significant short- and long-term detrimental impacts. Water bird and marine mammal populations can be destroyed, beaches can be rendered inconvenient or

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<sup>22</sup>Centaur Associates, Inc., Assessment of Space and Use Conflicts Between the Fishing and Oil Industries, 3 vols. (New York: Bureau of Land Management, U.S. Department of Interior, 1981).

<sup>23</sup>R.B. Stone, "Artificial Reefs and Fishery Management," Fisheries 3:2-4, 1978.

<sup>24</sup>Ronald Dugas, Vincent Guillory and Myron Fischer, "Oil Rigs and Off-shore Sport Fishing in Louisiana," Fisheries 4:2-10, 1979.

unusable for swimming by tar balls or crude oil, intertidal marshes can be killed back and intertidal animal populations affected for years following an oil spill incident. Not all coastal oil spills cause these adverse effects, but widely publicized spills have caused them, thus they will be feared. Some coastal spills have had minimal adverse impacts, but this is largely due to these spills having been carried offshore by wind and currents. Seaward of the barrier islands, wind and current patterns are such that some coastal spills will be dispersed offshore while others will be carried towards beaches and tidal inlets. In inside waters (bays, sounds and estuaries) the full impact of the spill will be borne by marine environments well known for their sensitivity to oil pollution.

At the same time, it is important to maintain a perspective on the likelihood of an oil spill. The offshore oil industry has compiled a commendable safety record in recent years. The spill rates currently used by the Minerals Management Service to estimate lease sale impacts are 1.0, 1.6, and 1.3 spills of 1,000 barrels or greater per billion barrels produced or transported for platforms, pipelines, and tankers, respectively.<sup>25</sup> Between 1971 and 1982, 55 spills over 50 barrels, totalling 67,979 barrels in all, occurred in the federal waters of the Gulf. During the same period, approximately 3.79 billion barrels of oil and condensate were produced, resulting in a spill rate of .0018%. Spills from well blowouts have become very rare. The last blowout to result in an oil spill in federal waters occurred in 1970; since then, over 12,000 wells have been drilled and 79 blowouts have occurred, none with spillage of more than a barrel.<sup>26</sup>

The environmental effects of oil spills include the physical impact of oil in coastal habitats and biological effects ranging across a spectrum from acute toxicity to long-term, sublethal disturbance. The severity of all impacts is influenced greatly by the type and age of oil spilled.

The term petroleum refers to a complex mixture of chemicals composed mostly of hydrogen and carbon (hydrocarbons). The chemistry of petroleum changes radically after it is spilled. These changes are caused by evaporation of light components and chemical and biological oxidation of heavier components. The changes lead to formation of pelagic tar that floats or sinks depending on its density. The differences between petroleum from different sources and at different ages from the same source make specific predictions of environmental impact impossible.

The general environmental impacts of oil spills in coastal habitats are well known. Pelagic tar is an environmentally long-lived end product of oil spill degradation, and tar on beaches is a predictable outcome of oil spills

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<sup>25</sup>Kenneth J. Lanfear and David E. Arnstutz, "A Reexamination of Occurrence Rates for Accidental Oil Spills on the U.S. Outer Continental Shelf," presented at the 1983 Oil Spill Conference, San Antonio, Texas; copies available from MMS. The figures for platforms and pipelines were based on OCS data, while the one for tankers is based on the worldwide spill record.

<sup>26</sup>U.S. Department of the Interior, Minerals Management Service, Federal Offshore Statistics (Washington, D.C.: Minerals Management Service, 1983), pp. 49, 53, 86-87.

in coastal waters. General biological effects are almost equally predictable. Animals that live at (water birds) or breathe through (marine mammals, sea turtles, etc.) the air-water interface are severely affected by oil spills.<sup>27</sup> Sea birds are particularly susceptible to oil because it sticks to their naturally oiled feathers and is ingested as the birds preen. While efforts to clean birds after oil spills have largely been unsuccessful in the past, considerable progress has been made in recent years in developing successful and cost-effective procedures. The Torrey Canyon oil spill killed 40,000 to 100,000 birds, mostly auks, on both sides of the English Channel.<sup>28</sup> Marine mammals also suffer greatly from contact with spilled petroleum. Those with hair (seals, otters, muskrats, etc.) have problems similar to those described for sea birds. Hairless marine mammals (whales, porpoises and the like) seem to have fewer problems. These animals have often been observed near major oil spills without showing obvious distress or mortality.<sup>29</sup> The impact of oil on sea turtles is not well known, although it has been suggested that the impact may be great because sea turtles not only breathe air, but also may be attracted to oil spills.

The impact of oil on aquatic, gill-breathing animals ranges from acute toxicity to sublethal effects of various sorts. Physical smothering of coastal organisms by oil is one of the most often observed features of an oil spill.<sup>30</sup> It is often difficult to determine the exact cause of death, but physical or chemical interference with feeding and respiratory activities are obviously involved. The catalog of sublethal effects of oil on marine animals is long and constantly expanding. The 1975 report of the U.S. National Academy of Sciences<sup>31</sup> includes a nine-page table summarizing 46 papers that document sublethal effects on reproduction, growth, metabolism, behavior, and cellular structure. Many of the species demonstrating these effects are found in North Carolina inshore waters.

## 5. Drilling Fluids and Cuttings

Drilling for oil is accomplished by a bit suspended on the end of a pipe, both of which are rotated by engines on the drilling platform. The rotating bit cuts through sediment and rock under the platform to reach potentially

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<sup>27</sup>A. Nelson-Smith, Oil Pollution and Marine Ecology (New York: Plenum, 1973), ix + 260pp.

<sup>28</sup>W.R.P. Bourne, "Special Review -- After the Torrey Canyon Disaster," Ibis 112:120-125, 1970.

<sup>29</sup>D.R. Goodale, M.A. Hyman, and H.E. Winn, "Cetacean Responses in Association with the Regal Sword Oil Spill," Chapter XI, pp.1-15 in: A Characterization of Marine Mammals and Turtles in the Mid and North Atlantic Areas of the U.S. Outer Continental Shelf, Ann. Report for 1979, USDOI BLM Contract #AA551-CT8-48, 1981.

<sup>30</sup>Nelson-Smith, Oil Pollution and Marine Ecology.

<sup>31</sup>National Academy of Sciences, Petroleum in the Marine Environment (Washington, D.C.: National Academy of Sciences, 1975), xi + 107pp.

oil-bearing strata. As the drill moves deeper into the substratum, new sections of pipe are added to extend its total length. Adding pipe adds weight and friction at the drill bit. The bit is lubricated and cuttings removed by fluids (drilling fluid or "mud") pumped inside the drill pipe. The pressure of the fluids is sufficient to flush through the hollow drill bit, clear it of rock and sediment cuttings, and transport these to the surface along the outside of the rotating drill string. Fluid pressure is also used to control seepage from surrounding strata into the drill hole. Since drill bits wear, and different bits are used in different substrates, the entire drill string must be periodically withdrawn from the hole. At these times the pressurized drilling fluid is the only force maintaining the well. The multiple important uses of fluids in oil drilling have led to development of a distinct technology for handling, cleaning, and using them. Fluids are usually maintained in tanks or pits on or near the drilling platforms. As much as 70 percent of the drilling site may be devoted to drilling fluid equipment and storage.<sup>32</sup> Waste fluids are discharged into the environment as cuttings are washed, fluid composition is adjusted or volume expands because of seepage. Fluids are also disposed of as a well is closed down or converted to production. More than two million tons (dry weight) of waste drilling fluids are discharged annually on the U.S. Outer Continental Shelf.<sup>33</sup> Some discharges of these materials can be expected if North Carolina waters are explored and developed for petroleum recovery.

The principal ingredients of drilling fluids are bentonite or attapulgite clays (to increase viscosity and create a gel), barium sulfate ("barite," a weighting agent), lime and caustic soda (to increase the pH and control viscosity), and various conditioning materials (polymers, starches, lignitic material, and other chemicals).<sup>34</sup> Most muds have a water base, but oil-based muds may be used in special situations, such as where bottom hole temperatures are very high, where water-based muds would hydrate water-sensitive clays, or where the drill pipe is stuck.<sup>35</sup> The chemicals used in a "typical" lignosulfonate drilling fluid system in a 15,000-foot well are presented in Table D-1.

The environmental impacts of drilling fluid disposal include physical alteration of the sediments where waste fluids are deposited and biological effects that vary widely depending on the specific type of fluid being discharged. Biological effects of drilling fluids are generally related to the minor components of drilling fluid, and these vary widely from fluid to fluid.<sup>36</sup> Diesel fuel is sometimes added to enhance lubrication of the drill

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<sup>32</sup>Longley et al., Managing Oil and Gas Activities: Refuge Manual.

<sup>33</sup>National Research Council, Drilling Discharges in the Marine Environment (Washington, D.C.: National Academy Press, 1983), p. 2.

<sup>34</sup>U.S. Environmental Protection Agency, Development Document for Interim Final Effluent Limitations Guidelines and Proposed New Source Performance Standards for the Oil and Gas Extraction Point Source Category, Publication EPA 440/1-76/055-a (Washington, D.C.: U.S.E.P.A., 1976), p.12.

<sup>35</sup>Ibid.

<sup>36</sup>National Research Council, Drilling Discharges in the Marine Environment.

Table D-1  
Drilling Fluid Components Used in Seawater-Lignosulfonate  
Systems to 15,000 Feet

Weight in Thousands of Pounds\*

	<u>Interval</u>		<u>Sub-</u> <u>total</u>	<u>Interval</u>	<u>Sub-</u> <u>total</u>	<u>Interval</u>	<u>TOTAL</u>
	0-	900-		3500-		10-	
	900	3500	3500	10,000	10,000	15,000	15,000
	Feet	Feet	Feet	Feet	Feet	Feet	Feet
Barium Sulfate (Barite)	3	3	6	529	535	625	1,160
Bentonitic Clay	10	10	20	36	56	9	65
Attapulgitic Clay	5	5	10	—	10	—	10
Caustic	0.5	0.5	1	20	21	23	44
Aromatic Detergent		1	1	2	3	—	3
Organic Polymers		1	1	3	4	—	4
Ferrochrome							
Lignosulfonate				26	26	69	95
Sodium Chromate						2	2
TOTALS	18.5	20.5	39	616	655	728	1,383 (691.5 tons)

\*These are "typical" values and quantities may vary by as much as 50 percent from well to well. (From U.S. Department of Interior, Bureau of Land Management, Final Environmental Statement, Proposed Five-Year OCS Oil and Gas Lease Sale Schedule, March 1980-February 1985 (Washington, D.C.: Bureau of Land Management, 1980), p. 151.)

bit, and as mentioned above oil-based fluids may be used in a variety of situations. Non-petroleum additions to drilling fluids can include hexavalent chromium for deflocculation control,<sup>37</sup> biocides to retard microorganism growth, and detergents and surfactants to decrease surface tension.<sup>38</sup>

<sup>37</sup>F. Knox, The Behavior of Ferrochrome Lignosulfonate in Natural Waters, M.S. Thesis, Mass. Inst. Tech., Cambridge, Mass., 1978. 65pp.

<sup>38</sup>R.C. Ayers, T.C. Sauer, Jr., R.P. Meek, and G. Bowers, "An Environmental Study to Assess the Impact of Drilling Discharges in the Mid-Atlantic on Environmental Fate and Effects of Drilling Fluids and Cuttings.

Drilling fluids discharged from shallow water drilling platforms are diluted by diffusive discharge, settle through the water column, and are incorporated into bottom materials. These processes occur over distances from the platform that differ in response to currents, environmental turbulence, and discharge diffuser design. Outfall diffusers can be designed to reduce drilling fluid concentrations by several orders of magnitude within a few the outfall pipe,<sup>39</sup> and observations of drilling fluid plumes show that concentrations drop to less than 50 parts per million (solids concentration) within 150 meters of the discharge point.<sup>40</sup> More than 90 percent of discharged drilling mud and cuttings settle directly to the seafloor.<sup>41</sup> Studies of sediment concentration of drilling fluid components around discharge points show that concentrations decrease inversely with radial distance, and in low current situations most of the solids settle within 1,000 meters of the discharge.<sup>42</sup> Resuspension and subsequent movement of settled drilling fluid particles can occur, but drilling fluids can be expected to alter bottom sediment type and chemistry near discharge sites in shallow water.

In general the biological impact of any waste materials placed in an environment can include acute toxicity, sublethal long-term effects and bioaccumulation in natural food chains. Drilling fluids have been studied in relation to all three impacts. The major ingredients of water based drilling fluids (barite, bentonite clays, etc.) are practically non-toxic, but ferrochrome-lignosulfonate and sodium hydroxide are moderately toxic (i.e., concentrations between 100-1000 ppm kill 50 percent of test organisms within 96 hours),<sup>43</sup> while biocidal constituents can be very toxic to marine organisms (concentrations of less than 1 ppm kill 50 percent of test animals within 96 hours). Sublethal long-term effects of drilling fluids on marine animals have been studied relatively little, but some impacts of practically non-toxic substances have been observed. Recruitment of sandy-bottom worms and molluscs

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I. Quantity and Fate of Discharges," pp. 382-418 in: Symposium on Research on Environmental Fate and Effects of Drilling Fluids and Cuttings (Washington, D.C.: Courtesy Associates, 1980).

<sup>39</sup>J.M. Colonell, ed., Port Valdez, Alaska: Environmental Studies, 1976-1979, Occ. Pub. 5 (Fairbanks, Alaska: Inst. Mar. Sci., 1981), 373pp.

<sup>40</sup>Ayers et al., "An Environmental Study to Assess the Impact of Drilling Discharges in the Mid-Atlantic."

<sup>41</sup>Ibid.

<sup>42</sup>D.A. Gettleson and C.E. Laird, "Benthic Barium in the Vicinity of Six Drill Sites in the Gulf of Mexico," pp. 739-788 in: Symposium on Research on Environmental Fate and Effects of Drilling Fluids and Cuttings (Washington, D.C.: Courtesy Associates, 1980).

<sup>43</sup>J.B. Sprague and W.L. Logan, "Separate and Joint Toxicity to Rainbow Trout of Substances Used in Drilling Fluids for Oil Exploration," Environ. Pollut. 19:269-281, 1979.

was significantly inhibited by barite,<sup>44</sup> and some species of shrimp accumulate barium abnormally when exposed to barite for long periods.<sup>45</sup> Biological accumulation of heavy metals from drilling fluids has been observed in experiments with animals of the sort that occur in North Carolina waters. These experiments show that worms, clams, shrimp, and mussels take up such metals as chromium, cadmium, lead, and zinc and do not rid themselves of these metals even after being kept in metal-free sea water for periods of up to 14 days.<sup>46</sup>

The recent National Academy of Sciences report on Drilling Discharges in the Marine Environment is the most comprehensive study of this problem yet.<sup>47</sup> While the study was directed at the U.S. Outer Continental Shelf, many of its findings can be extended with care to nearshore waters. The study included a useful summary table of the biological effects of drilling fluid components (reproduced here as Table D-2); the data summarized in this table and considered in greater detail in the NAS report led the NAS panel to conclude:

Based on laboratory and field studies to date, most water-based drilling fluids used on the U.S. OCS have low acute and chronic toxicities to marine organisms in light of the fluids' expected or observed rates of dilution and dispersal in the ocean after discharge. Their effects are restricted primarily to the ocean floor in the immediate vicinity and for a short distance downcurrent from the discharge. The bioaccumulation of metals from drilling fluids appears to be restricted to barium and chromium and is observed to be small in the field.<sup>48</sup>

## 6. Formation Waters

Sedimentary strata that contain petroleum also contain water. Initially it was thought that petroleum and water were not mixed in subsurface deposits,

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<sup>44</sup>M.E. Tagatz, J.M. Ivey, C.E. Dalbo, and J.L. Oglesby, "Responses of Developing Macrobenthic Communities to Drilling Muds," Estuaries 5:131-137, 1982.

<sup>45</sup>A.C. Brannon and K.R. Rao, "Barium, Strontium, and Calcium Levels in the Exoskeleton, Hepatopancreas, and Abdominal Muscle of the Grass Shrimp Palaemonetes pugio: Relation to Molting and Exposure to Barite," Comp. Biochem. Physiol. 63A:261-274, 1979.

<sup>46</sup>D.S. Page, B.T. Page, J.R. Hotham, and others, "Bioavailability of Toxic Constituents of Used Drilling Muds," pp. 984-996 in: Symposium on Research on Environmental Fate and Effects of Drilling Fluids and Cuttings (Washington, D.C.: Courtesy Associates, 1980); W.L. McCulloch, J.M. Neff, and R.S. Carr, "Bioavailability of Heavy Metals from Used Offshore Drilling Muds to the clam Rangia cuneata and the oyster Crassostrea gigas," in: Symposium on Research on Environmental Fate and Effects of Drilling Fluids and Cuttings (Washington, D.C.: Courtesy Associates, 1980).

<sup>47</sup>National Research Council, Drilling Discharges in the Marine Environment.

<sup>48</sup>Ibid., p. 112.

Table D-2

Summary of Biological Effects of Drilling Fluids and  
Drilling Fluid Ingredients on Marine Animals

Parameter	LABORATORY STUDIES	
	Acute Lethal Bioassays (LC50 Range, ppm)	Chronic/Sublethal Effects*
<b>Drilling Fluid Ingredients</b>		
Barite, Bentonite, Lignite	>10,000	5mm layer on sediment
Chrome- & Ferrochrome- lignosulfonates	120-12,000	50 ppm
Chromium (VI)	0.5-250	12 ppb
Diesel Fuel	0.1-1,000	10 ppb water, 100 ppm sediment
Paraformaldehyde	0.07-30	10 ppb
Detergents, Surfactants	0.4-14,000	---
Used Drilling Fluids	of 400 Bioassays: 38% > 100,000 41% 10,000-99,999 12% 1,000-9,999 6% 100-999 0.5% < 100 3% LC50 not deter- minable	1-160,000 ppm in water 1-12 mm layer on bottom 50-100,000 ppm affects recruitment to microcosms; some bioaccumulation of barium and chromium demonstrated.

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FIELD STUDIES

Community Responses	Effects seen only on benthos in the vicinity of discharge and are most pronounced in low-energy environments where discharges accumulate on bottom.
Bioaccumulation of Metals**	Small uptake of barium and chromium immediately after drilling

\*Lowest concentration at which effects are observed.

\*\*There are no specific data available on the bioaccumulation of hydrocarbons.

From: National Research Council, Drilling Discharges in the Marine Environment (Washington, D.C.: National Academy Press, 1983), p. 111.

but now it is known that these compounds occur together, often as an emulsion. As a result, oil production recovers water as a byproduct. The water recovered from oil wells is known variously as formation water (since it occurs in the same geological formation as the oil) or produced water (since it is produced along with the oil). The amount of this water varies in different oil fields and at different times in the development of the same field. Most commonly the ratio of water to oil increases as oil is pumped from the field. Over the life of an oil field, the U.S. Geological Survey estimates that the ratio of recovered water to recovered oil is 0.8, i.e. for every barrel of oil recovered, 0.8 barrels of formation water is also recovered. In old oil fields the recovered fluid may be five percent oil and 95 percent water.<sup>49</sup>

The composition of formation waters varies widely, but usually includes lithium, sodium, potassium, rubidium, cesium, calcium, magnesium, strontium, barium, boron, copper, chloride, bromide, iodide, bicarbonate, carbonate, sulfate, organic acids, and ammonium.<sup>50</sup> Most of these elements occur at concentrations much higher than that of sea water, and the overall concentration of salts is commonly three to ten times as high as normal sea water. The relative proportions of salts in formation waters and sea water differ, however. Rittenhouse and others<sup>51</sup> studied 823 oil field brines and found that manganese, lithium, chromium, and strontium were enriched relative to sea salt and tin, nickel, magnesium and potassium were depleted.

In the early days of oil production formation waters were simply dumped nearby and allowed to kill surface vegetation and the fish in streams draining the oilfield, but now these brines are often injected back into the oil formation to increase petroleum recovery and, in some cases, control land subsidence.<sup>52</sup> In many nearshore and Outer Continental Shelf oil wells, however, these brines are disposed of at sea.

Disposal of formation waters in marine waters must meet EPA requirements that these waters contain no more than 72 mg/l of oil. Statistical analyses of formation water discharged in the Gulf of Mexico show an average oil content of 25 mg/l petroleum.<sup>53</sup> EPA does not regulate disposal of chemicals other than oil in formation waters. Some of the chemicals in formation waters (e.g., copper) are known to be toxic to marine organisms, but the wide variability in composition and amount of formation water produced makes it impossible to realistically predict the impact of environmental disposal of such

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<sup>49</sup> A. Gene Collins, "Geochemistry of Oilfield Waters," in: Developments in Petroleum Science, Vol. 1 (New York: Elsevier, 1975), i + 496 pp.

<sup>50</sup> Ibid.

<sup>51</sup> G. Rittenhouse, R.B. Fulton, R.J. Grabowski, and J.L. Bernard, "Minor Elements in Oil Field Waters," Chem. Geol. 4:189-209, 1969.

<sup>52</sup> A. Gene Collins, "Geochemistry of Oilfield Waters."

<sup>53</sup> U.S. Department of the Interior, Minerals Management Service, Final Environmental Impact Statement, OCS Sale 78, Proposed 1983 Outer Continental Shelf Oil and Gas Lease Sale Offshore the South Atlantic States (Washington, D.C.: Minerals Management Service, 1983), p. 155.

waters from a virgin oil field. Some states have enacted more stringent controls. California, for instance, regulates effluent concentrations of more than a dozen different metals and toxic compounds in produced waters for offshore disposal. The oil and gas industry has found it more practical to reinject formation waters than to treat them for surface disposal.

It is possible that environmental disposal of formation waters would have an adverse environmental impact on the biologically productive nearshore waters of North Carolina. Such disposal may need to be regulated, and it may be appropriate to require reinjection of formation waters rather than offshore disposal.

## 7. Other Discharges

In addition to drilling muds and cuttings and formation waters, several other types of liquid wastes may be routinely generated at offshore well sites:<sup>54</sup>

- 1) deck drainage (all waste resulting from platform washings, deck washings, and run-off from curbs, gutters, and drains, including drip pans and work areas);
- 2) sanitary waste;
- 3) domestic waste (materials discharged from sinks, showers, laundries, and galleys);
- 4) cooling water ("noncontact" water used for cooling machinery); and
- 5) desalinization unit discharges (generated by desalinization of salt water).

The volume of liquid wastes generated varies widely with platform characteristics, operating schedule, occupancy, and other factors. Data gathered by EPA for several offshore facilities whose staffing ranged from 10 to 76 men showed combined domestic and sanitary waste production ranged from 1,000 to 5,500 gallons per day.<sup>55</sup> Deck drainage and heating and cooling waters discharged from platforms amount to roughly 90 gallons per day.<sup>56</sup> Mobil estimated that total liquid wastes (including domestic and sanitary wastes, deck drainage, drilling mud liquids, and various wash waters) from their drilling

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<sup>54</sup>U.S. Department of the Interior, Final Regional Statement, Vol. 1, p. 364; U.S. Environmental Protection Agency, Development Document, p. 38.

<sup>55</sup>U.S. Environmental Protection Agency, Development Document, p. 52.

<sup>56</sup>U.S. Department of the Interior, Bureau of Land Management, Final Supplement to the Final Environmental Statement, Proposed Five-Year OCS Oil and Gas Lease Sale Schedule, January 1982-December 1986, 2 Vols. (Washington, D.C.: Bureau of Land Management, 1982), Vol. 1, p. 270.

operations in Mobile Bay would average 9800 gallons per day per drilling barge.<sup>57</sup>

Treatment practice for these wastes varies. Deck drainage may be treated separately or along with formation waters to remove oil and grease; this treatment may be carried out on the platform or onshore. Sanitary wastes are usually treated on the platform with some combination of physical/chemical or physical/biological treatment, but in some cases they are tanked to shore for disposal. Domestic wastes only require grinding to eliminate floating solids.

Discharge of these wastes is regulated to some extent by EPA through the National Pollutant Discharge Elimination System (NPDES). Effluent limitations have been established for oil and grease, residual chlorine (as a substitute for fecal coliform), and floating solids, though these standards do not apply in all situations.<sup>58</sup> Some states have enacted more stringent and/or comprehensive regulations. Alabama, for instance, has implemented a no-discharge policy for offshore wells: all wastes, including deck drainage, domestic wastes, and others, must be transferred to shore for disposal.

#### 8. Air Pollution

In most areas air pollutant emissions from offshore oil and gas operations create little concern, since such operations do not generate large volumes of pollutants (relative to many other industrial facilities), and since sources are often miles from the nearest land, allowing pollutants to be diluted and dispersed over substantial distances before landfall is made. However, near urban or industrial concentrations where onshore air quality is already poor (as in southern California), or near pristine areas where any air quality degradation is noticeable, emissions from offshore operations may receive considerable attention.

Offshore emissions may be divided into two categories: those from routine operations and those generated during accidents. The major source of routine emissions during exploration will be power generation equipment. Mud pumps and rig drawworks are the principal consumers of electricity during drilling; additional power is needed to supply the rotary and various accessories and housekeeping activities. If convenient, the power may be supplied by cable from shore, but more often it is generated at the drilling site by diesel-fired turbines or (usually) reciprocating engines.<sup>59</sup>

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<sup>57</sup>U.S. Army Corps of Engineers (Mobile District), Final Statement for Four Exploratory/Appraisal Wells, p. C-8.

<sup>58</sup> 40 CFR §435; see also U.S. Environmental Protection Agency, Development Document.

<sup>59</sup>Richard H. Stephens, Charles Braxton, and Maynard M. Stephens, Atmospheric Emissions from Offshore Oil and Gas Development and Production, Publication EPA-450/3-77-026 (Research Triangle Park, N.C.: U.S. Environmental Protection Agency, 1977), pp. 81-83.

Other sources of emissions during exploration are the dredging and construction equipment used to build an access canal or road to the drill site, and the supply boats that ferry supplies and crew to the rig. In addition, if the drill bit passes through a gas reservoir, gas may seep into the well bore and become dissolved or entrained in the drilling mud. When this happens, mud degassing equipment must be used at the surface to remove any gas from the mud, and the liberated gas is then vented to the atmosphere.<sup>60</sup>

These activities and their associated emissions continue during field development, but added to them are the emissions generated by vessels and equipment engaged in platform construction and pipeline installation. The amount and location of these latter emissions will vary tremendously with platform and pipeline design, construction methods, and other factors.

The major source of emissions during the production phase will be power generation for gas compression (for artificial gas lift, re-injection, and/or transmission to shore), oil pumping (for other artificial lift methods and transmission to shore), water injection (for water flood or formation water disposal), and various miscellaneous uses (lighting, cooking, process motors, etc.).<sup>61</sup> Other emissions during production include those from direct-fired heaters used in processing the produced fluids, fugitive emissions from compressor, pump, and valve seals, and gas vented from storage tanks. If oil is barged to shore, large amounts of hydrocarbons can be emitted by the displacement of hydrocarbon vapor during barge loadings, and to a lesser extent by tanker cargo breathing.<sup>62</sup>

Representative emissions from these activities are shown in Table D-3. The combination of platform and pipeline construction and high production levels normally results in peak emission rates occurring during the year after production begins. Emissions decrease abruptly with the end of construction activity and continue to decline as production levels decline.<sup>63</sup>

Accidents involving loss of well control -- oil spills, blowouts, and fires -- have the potential for releasing significant quantities of pollutants to the atmosphere. One study estimated that hydrocarbons are emitted from an oil spill at the rate of 57 lbs/barrel during the first hour of the spill and 29 lbs/barrel during the second hour.<sup>64</sup> Blowouts release hydrocarbons at rates comparable to the full production rate of the well, which for a well

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<sup>60</sup>Ibid., p. 89.

<sup>61</sup>Ibid., p. 93.

<sup>62</sup>U.S. Department of Interior, Final Supplement, Vol. 1, p. 169; U.S. Department of Interior, Bureau of Land Management, Final Environmental Statement, Proposed Five-Year OCS Oil and Gas Lease Sale Schedule, March 1980-February 1985 (Washington, D.C.: Bureau of Land Management, 1980), p. 154.

<sup>63</sup>U.S. Department of Interior, Final Statement, 1980-1985, p. 154.

<sup>64</sup>U.S. Department of Interior, Final Supplement, Vol. 1, p. 169.

Table D-3

## Operational Emissions from Offshore Oil and Gas Activities

Activity	Pollutant Emissions (tons/year)					Notes
	VOC	NO <sub>x</sub>	TSP	SO <sub>2</sub>	CO	
Exploration Drilling	18	180	13	12	40	Emissions valued from VCAPD (1981) assumes 60 days/well and 6 wells drilled near same site, i.e., constant drilling in same area over the full year.
Platform Installation	16	465	22	31	75	Emission values from ERG (1981) assumes platform installation occurs over 9 months; includes support activities.
Development Drilling	9	240	11	21	71	Emission values from ERG (1981) assumes 2 wells drilled at a time and 12 wells per year.

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Activity	Power Requirement
Oil Production	
Electrical Generation (oil pumping, platform electricity, miscellaneous)	5,300 hp-hr/10 <sup>3</sup> bbls.
Water Injection	3,000 hp-hr/10 <sup>3</sup> bbls.
Barge loading - 1.7 lb Hc per 10 <sup>3</sup> gal transferred (crude oil)	
Gas Production and Processing	
Gas Compression (lift, gathering, sendout)	6,100 hp-hr/10 <sup>6</sup> ft. <sup>3</sup>
Offshore Gas Processing (compression for heavy hydrocarbon removal, sweetening, dehydration)	3,200 hp-hr/10 <sup>6</sup> ft. <sup>3</sup>

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(continued on next page)

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Table D-3 (continued)

Note: Emissions factors for power requirements are as follows (pounds/10<sup>3</sup> hp-hr):

NO <sub>x</sub>	CO	HC	SO <sub>2</sub>	TSP
2.9	1.1	0.2	0.004	NA

Source: U.S. Department of Interior, Bureau of Land Management, Final Supplement to the Final Environmental Statement, Proposed Five-Year OCS Oil and Gas Lease Sale Schedule, January 1982-December 1986, 2 Vols. (Washington, D.C.: Bureau of Land Management, 1982), Vol. 1, pp. 382-383.

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producing one million cubic feet per day is roughly 2000 lbs/hour.<sup>65</sup> Gas reservoirs also frequently contain hydrogen sulfide, and during blowouts concentrations of H<sub>2</sub>S near the rig may approach dangerous levels. If the escaping gas is accidentally or purposely flared, typical combustion emissions (nitrogen and sulfur oxides, carbon monoxide, particulates) will replace the hydrogen sulfide and much of the hydrocarbon emissions. Representative emission rates from these accidents are given in Table D-4.

Finally, offshore exploration and production may be accompanied by emissions from a variety of onshore sources, including support bases, fabrication yards, pump and compressor stations, oil refineries, and gas processing plants. Representative emission rates for these facilities have been compiled by the New England River Basins Commission.<sup>66</sup>

## 9. Employment

Employment benefits to the local economy are generally small during exploration but increase during development and production. In an OCS exploratory program, a total of 130 to 200 people will be employed on the rig and in operating supply boats, helicopters, and onshore support services. A typical drill barge used in nearshore waters, with attendant supply and onshore services, will require only 75 personnel, including two shifts of 30 each on the barge itself.<sup>67</sup> Most of these employees will be skilled transients, working 7-14 day shifts on the drilling vessels and usually flying home during their weeks off. There will be relatively few local hires.

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<sup>65</sup>Ibid.; Stephens et al., Atmospheric Emissions, p. 91.

<sup>66</sup>New England River Basins Commission, Factbook.

<sup>67</sup> John Clark, Jeffrey Zinn, and Charles Terrell, Environmental Planning for Offshore Oil and Gas, Volume 1: Recovery Technology, Publication No.

Table D-4

## Representative Emissions of Catastrophic Events

Accident Type	Emissions (lbs/hr)					
	THC	NO <sub>x</sub>	SO <sub>x</sub>	CO	TSP	H <sub>2</sub> S
140 Barrel Spill						
First Hour	8,000	--	--	--	--	--
Second Hour	4,100	--	--	--	--	--
10,000 Barrel Spill						
First Hour	570,000	--	--	--	--	--
Second Hour	290,000	--	--	--	--	--
(Evaporation losses during the first 10 days of an oil spill are assumed to be approximately 45%)						
Blowout-No Fire*	2,000	--	--	--	--	33
Blowout-With Fire*	670	46	417	670	140	--

\*Assuming blowout 1,000 mcf/d and 1,000 bod.

Source: U.S. Department of Interior, Bureau of Land Management, Final Supplement to the Final Environmental Statement, Proposed Five-Year OCS Oil and Gas Lease Sale Schedule, January 1982-December 1986, 2 Vols. (Washington, D.C.: Bureau of Land Management, 1982), Vol. 1, pp. 382.

During field development and production, the number of employees, the percentage of local hires, and the amount of in-migration are all likely to increase. For example, Tables D-5 and D-6 show estimated employment during development and production, respectively, for the Lower Mobile Bay Gas Field in Alabama being developed by Mobil. Development plans call for five production platforms, up to 20 wells, a pipeline system, and gas processing plant.

The secondary employment multiplier will increase from negligible levels during exploration to perhaps 0.5 for the development phase and 1.0 for production.

FWS/OBS-77/12 (Washington, D.C.: Office of Biological Services, U.S. Fish and Wildlife Service, 1978), p. 72; Interstate Electronics Corporation, "Environmental Report-Exploration, South Atlantic OCS, Lease Sale 56, Blocks 422, 466, 510, Manteo Area," prepared for Chevron U.S.A., Inc., 1982, p. 2-3; U.S. Army Corps of Engineers (Mobile District), Final Statement for Four Exploratory/Appraisal Wells, p. 57.

Table D-5

Employment During the Construction Phase of  
Development of the Lower Mobile Bay Field, Alabama

Activity	Estimated Duration of Work	Estimated Peak Construction Employment	Estimated Local Hires
Drilling	6 years	90	5
Drilling Services	6 years	70	35
Offshore Site Preparation	1 month/platform*	20	10
Platform Installation	1 month/platform*	80	5
Offshore Facilities	4 to 6 months*	40	5
Offshore Pipeline Installation	5 months	120	10
Onshore Pipeline Installation	3 months	100	60
Gas Plant Construction	12 months	350	225
Road and Other Construction	3 months	50	35
Sulfur Depot/ Railroad Spur	3 months	<u>80</u>	<u>60</u>
TOTALS		1,000	450

\*Work will not be performed at the same time for each platform.

Source: U.S. Army Corps of Engineers (Mobile District), Production of Natural Gas from the Lower Mobile Bay Field, Alabama, Final Environmental Impact Statement (Mobile, Ala.: U.S. Army Corps of Engineers, 1982), p.4-44.

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Table D-6

Employment During the  
Operation Phase of Development of the Lower  
Mobile Bay Field, Alabama

Location of Employment	Estimated Employment	Estimated Local Hires
Bayou La Batre	6	1
Boats	6	4
Platforms	24	10
Plant	27	10
Sulfur Depot	<u>7</u>	<u>3</u>
TOTAL	70	28

Source: U.S. Army Corps of Engineers (Mobile District), Production of Natural Gas from the Lower Mobile Bay Field, Alabama, Final Environmental Impact Statement (Mobile, Ala.: U.S. Army Corps of Engineers, 1982), p.4-45.

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## APPENDIX E

### Legislation, Regulation, and Permitting

This appendix is divided into two parts and serves as a supplement to Chapter 3. The first section gives a brief description of state and federal legislation that will influence the exploration and development of submerged lands for oil and gas. This section is divided by subject area into laws dealing with environmental protection, navigation and construction, business and employment practices, and historic and cultural preservation. Where one piece of legislation applies to more than one of these subject areas, it has been classified under the most significant topic.

The second portion of this appendix lists and describes permitting, licensing, and certification requirements at both state and federal levels. This section has been divided into four phases of oil and gas operations, designated the Pre-lease, Exploration, Field Development, and Production stages. Where one permit might be required in more than one phase, it has been listed under the phase in which it first becomes necessary.

#### I. Legislation

##### A. Laws Concerning Environmental Protection

###### 1. Water Quality

Several pieces of federal and state legislation deal specifically with the prevention and control of water pollution, both from regular discharges of noxious materials and from oil spills. The Federal Water Pollution Control Act (FWPCA), 33 U.S.C. §1251 et seq., establishes effluent standards and provides for Coast Guard enforcement of the standards. Under this authority the Coast Guard enforces the prohibitions against oil and oily waste discharges by conducting pollution and surveillance patrols. (§1321)

Amendments to the FWPCA in 1972 created the National Pollutant Discharge Elimination System (NPDES), which applies to any project resulting in discharges to surface waters in territorial seas, including the three-mile zone, the contiguous zone, and oceans. Under NPDES, EPA permits (now administered by the N.C. Division of Environmental Management) are required for discharges from fixed platforms and drillships, including both gradual and bulk discharges of drilling muds. Under the procedures and criteria for NPDES permits, the activity being permitted may cause "no unreasonable degradation of the marine environment."<sup>1</sup> Also required under the 1972 amendments are:

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<sup>1</sup>40 CFR 125.122 et seq.

Coast Guard approval of procedures and equipment for transferring oil;<sup>2</sup> certification that discharges are in compliance with state water quality standards;<sup>3</sup> and permits for the discharge of dredge and fill materials into U.S. waters.<sup>4</sup> For more information on these permits, see Part II, "Permitting, Licensing, and Certification."

The North Carolina Oil Pollution and Hazardous Substance Control Act of 1978 (N.C. Gen. Stat. §143-215.75 et seq.) is a follow-up measure to the FWPCA 1972 amendments. It is not meant to apply where there is exclusive federal jurisdiction, but rather to "support and complement" applicable federal laws. The Act's stated purpose is to promote the health, safety, and welfare of North Carolina citizens by protecting land and water under state jurisdiction from pollution by oil, oil products, oil by-products, and other hazardous substances. To accomplish this purpose, it mandates the establishment of an oil pollution control program under the Department of Natural Resources and Community Development (NRCD). The control measures include permits for the discharge of oil, permits for refining facilities, registration of oil terminal facilities, and immediate clean-up of damages by those "having control over" discharges which damage property and/or injure wildlife, fish, or natural resources.

There are several other pieces of legislation dealing with water pollution and conservation. A federal act relating to prevention of pollution from ships was codified in 1980 at 33 U.S.C. §1901. The act supersedes, in part, the Oil Pollution Act of 1961, and mandates Coast Guard enforcement of the MARPOL Protocol of 1978, which resulted from the International Convention for the Prevention of Pollution from Ships of 1978. The act requires certificates of adequacy of port or terminal facilities for the transfer of oil or noxious liquids.

Miscellaneous provisions under Title 143, Article 21, of the North Carolina General Statutes (N.C. Gen. Stat. §143-211 et seq.) establish state policy on air and water conservation and create the Environmental Management Commission (EMC) to administer pollution control and water resources management programs. These statutes prohibit the discharge of wastes into ocean waters under North Carolina jurisdiction except where EMC regulations permit it,<sup>5</sup> prohibit discharge of waste to subsurface or groundwaters by means of a well,<sup>6</sup> and require a permit from EMC for the discharge of any waste, directly or indirectly, in violation of applicable water quality standards.<sup>7</sup> The Water

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<sup>2</sup>33 U.S.C. §1342.

<sup>3</sup>33 U.S.C. §1341; §401 of the 1972 Act.

<sup>4</sup>33 U.S.C. §1344; §404 of the 1972 Act.

<sup>5</sup>N.C. Gen. Stat. §143-215.2(c).

<sup>6</sup>N.C. Gen. Stat. §143-214.1(b).

<sup>7</sup>N.C. Gen. Stat. §143-214.1 et seq., and -215.1 et seq.

Use Act of 1967 (N.C. Gen. Stat. §143-215.11-.22) sets state policy for water conservation. It requires the issuance of water use permits from the EMC for large projects in specified "capacity use areas." Although the single designated capacity use area includes a large portion of the coastal plain, most oil and gas operations, at least prior to the field development stage, will not use enough water to require a permit. Additionally, under the Water and Air Quality Reporting Act of 1971 (N.C. Gen. Stat. §143-215.63) all persons subject to EMC water pollution regulations are required to file reports on discharges to EMC at least quarterly. State legislation also enables local governments to have ordinances and regulations regarding the control of oil pollution (N.C. Gen. Stat. §143-215.82).

To mitigate the damage caused by oil spills, the federal Clean Water Act, incorporated into FWPCA at 33 U.S.C. §1321, holds the owner or operator of any vessel or facility liable for the costs of removing spills of oil or hazardous substances attributable to that vessel or facility. In addition, other penalties may be charged. Under the Act, the Council on Environmental Quality prepared a National Contingency Plan for the removal of oil and hazardous substances and an emergency procedure for preventing the adverse effects of oil spills.

The Comprehensive Environmental Response, Compensation and Liability Act of 1980 (CERCLA), 42 U.S.C. §9605, charged the Environmental Protection Agency with revising the National Contingency Plan. This revised plan, the National Oil and Hazardous Substances Pollution Contingency Plan, at 40 CFR 300, coordinates the actions of the federal government in the efficient control and clean-up of spills and encourages state and local governments to develop plans consistent with the federal one.

In 1981, North Carolina adopted its Hazardous Materials Emergency Response Plan as mandated under the Water and Air Quality Reporting Act, the Oil Pollution and Hazardous Substances Control Act of 1978, and the Air and Water Pollution Control Act, and as urged by the National Contingency Plan. The State plan establishes the duties of all involved state agencies in responding to hazardous materials emergencies, including oil spills, in the State of North Carolina. The Division of Environmental Management in NRCD is primarily responsible for coordinating spill containment and clean up and taking action against the perpetrators of unlawful spills.

## 2. Air Quality

Although offshore oil and gas drilling may not immediately evoke thoughts of air pollution, emissions from a variety of sources do occur and will be governed by both state and federal legislation. The major piece of federal legislation is the Federal Clean Air Act (42 U.S.C. §7401 et seq.). This act allows the transfer of air quality permitting authority to the state, with EPA oversight, once a State Implementation Plan has been approved, as North Carolina's has.<sup>8</sup> The Act establishes a set of National Ambient Air Quality Standards (NAAQS), which set the maximum acceptable levels for a number of common pollutants. If a new source of air pollution is located in an

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<sup>8</sup>40 CFR 42.1772.

"attainment area" (i.e., one meeting NAAQS, as do all North Carolina coastal counties) and if it will emit more than 250 tons/year of a regulated pollutant (or 100 tons/year if it is one of a select number of industrial facilities, including oil storage terminals with capacity greater than 500,000 barrels and oil refineries) it is required to obtain a Prevention of Significant Deterioration of Air Quality (PSD) permit before commencing construction, showing that the pollution controls used will be the "best available control technology."

Similarly, under Title 143, Article 21B of the North Carolina General Statutes, the state government has set up a process of state air quality controls and permitting, administered by the Division of Environmental Management (DEM). DEM is charged with responsibility for the adoption of air quality standards, emission control standards, and classification of air contaminant sources, and with oversight of local air pollution control programs.<sup>9</sup> The controlling legislation also requires an EMC permit for the construction or operation of any air contaminant source or polluting equipment. (More information on these permits is included in Part II of this Appendix.)

### 3. Coastal Resources

The Federal Coastal Zone Management Act of 1972, 16 U.S.C. §1451, establishes a national policy for the protection of coastal areas and encourages planning and management at local and state levels. Once a state has a federally approved coastal zone management program, as does North Carolina, any federal actions in a coastal area, including licenses and permits, must be certified by the state as consistent with the state's coastal program.<sup>10</sup> When the applicant for a permit determines that the proposed activity meets the state requirements, he declares this in the application and forwards the application to the state, which has its own internal process for comment and approval.<sup>11</sup>

The North Carolina Coastal Area Management Act of 1974 (CAMA; N.C. Gen. Stat. §113A-100 - §113A-128) calls for a comprehensive state planning and management program to protect public interests unique to the coastal zone and to "ensure the orderly and balanced use and preservation of our coastal resources on behalf of North Carolina and the nation." Under the program established, a permit is required from the state for "major developments" in "Areas of Environmental Concern" (AEC). Oil and gas drilling is by definition a major development, and all submerged lands fall into one or more categories of AECs. The Act also provides for locally-approved "minor development" permits for certain activities and requires coastal towns and counties to develop land use plans. Under Executive Order #15 of Governor Hunt, "all state agencies shall take account of and be consistent to the maximum extent

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<sup>9</sup>N.C. Gen. Stat. §143-215.105 et seq.

<sup>10</sup>16 U.S.C. §1456(e)(3).

<sup>11</sup>15 CFR 930-D.

possible with" North Carolina coastal policy and must consult and coordinate their activities with the Coastal Resources Commission.

#### 4. Other Environmental Concerns

Two other topics of concern are soil conservation and protection of fish and wildlife. Under the North Carolina Sedimentation Pollution Control Act of 1973 (N.C. Gen. Stat. §113A-50 - §113A-66) the Sedimentation Control Commission was charged with setting up an erosion and sedimentation control program. Under this program, every developer must file a sedimentation control plan with the Division of Land Resources in NRCD for any change to the natural cover or topography which might cause or contribute to sedimentation on a lot of one acre or more. Local governments may supersede the state law with erosion control ordinances at least as stringent as the state's. Major onshore facilities associated with offshore drilling will be subject to the requirements of this statute.

Both the federal and North Carolina legislatures have enacted laws for the protection of fish and wildlife. The Endangered Species Act of 1973, 16 U.S.C. §1531, requires every federal department or agency, in consultation with the Secretary of the Interior, to insure that none of its actions (including permitting) jeopardizes any listed species. Jurisdiction over the various species is divided between the U.S. Fish and Wildlife Service and the National Marine Fisheries Service. The Federal Fish and Wildlife Coordination Act (16 U.S.C. §661 et seq.) requires "that wildlife conservation shall receive equal consideration and be coordinated with other features of water-resource development programs." To ensure that this is done, the Act requires the project agency to consult with the U.S. Fish and Wildlife Service, and in North Carolina the Wildlife Resources Commission, before any federal licensing in streams or other bodies of water. Although it is unlikely to apply to offshore drilling, the Marine Mammal Protection Act, 16 U.S.C. §1361, makes it illegal for any person, vessel, or conveyance to "take" any mammal in waters under U.S. jurisdiction, unless under a restricted permit from the Secretary of the Interior or the National Oceanic and Atmospheric Administration. "Taking" includes harassing, hunting, capturing, killing, or attempting to do so.

In the state's territorial waters, the North Carolina Marine Fisheries Commission (MFC), under NRCD, has jurisdiction over the conservation of marine and estuarine resources. Although the relevant legislation, N.C. Gen. Stat. §113-127 et seq., applies primarily to commercial fishing operations, the MFC is consulted when permits for excavation or filling in coastal areas are granted and is required to conduct public hearings if objections to these permits are filed (N.C. Gen. Stat. §113-229). The MFC regulations have superseded most local regulation of marine and estuarine resources, but MFC has no jurisdiction over matters which are clearly under the control of the Department of Agriculture, the N.C. Pesticide Board, the Commission for Health Services, the EMC, or any other NRCD division regulating air or water pollution (N.C. Gen. Stat. §§113-133, 133.1, 132(c)).

#### D. Laws Concerning Navigation and Construction

The primary piece of legislation regarding navigational safety is the U.S. Ports and Waterways Safety Act (33 U.S.C. §§1221-1232). This act gives the U.S. Coast Guard primary responsibility for port and navigational safety, including control of traffic flow (timing and routing of vessels), procedures and safeguards for handling cargo, and minimum safety equipment for structures. Pursuant to the Act, dozens of regulations have been issued regarding general permits for handling dangerous cargo such as liquid petroleum gas (LPG) and crude oil at port;<sup>12</sup> Coast Guard direction of moving or loading oil on sea structures or at port,<sup>13</sup> providing notice of hazardous conditions on board exploratory vessels,<sup>14</sup> bulk carrying of hazardous or flammable cargo,<sup>15</sup> labelling of hazardous substances, including crude oil and LPG, in transit,<sup>16</sup> and the certification of non-bulk (containerized) shipment.<sup>17</sup>

State statutes at N.C. Gen. Stat. §76-40 also regulate certain practices in navigable waters under state jurisdiction. Among these laws are the prohibition of trash, refuse, or scrap in navigable waters, the requirements for obtaining construction permits and for removing structures within 30 days of abandonment, the jurisdiction of NRC and EMC to enforce the Act in coastal waters, and other provisions relating to specific coastal areas.

Several state and federal laws deal with construction activities in coastal areas, several of which are discussed in greater detail in Part II of this chapter. The primary federal act under this topic is the Rivers and Harbors Act of 1899 (33 U.S.C. §401 et seq.), which is applicable to any construction of new harbors or structures which might obstruct navigable waters. A permit is required from the Army Corps of Engineers for all offshore construction or work in U.S. navigable waters.

The North Carolina Dredge and Fill Act (N.C. Gen. Stat. §§113-229) requires a permit from the Office of Coastal Management for any dredging and filling in estuarine waters, tidelands, and other waters, including the three-mile zone. For construction of drilling rigs, support bases, terminals, refineries or other structures needed at various stages of oil and gas activities both onshore and off,<sup>18</sup> local land use regulations and construction codes must also be considered.

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<sup>12</sup>33 CFR 126.27.

<sup>13</sup>33 CFR 160.106.

<sup>14</sup>33 CFR 161.1.

<sup>15</sup>33 CFR 153, 154.

<sup>16</sup>49 CFR 172.101.

<sup>17</sup>49 CFR 176.27, .5.

<sup>18</sup>Counties may now regulate development over estuarine waters and lands covered by navigable waters owned by the State, by an Act of the General Assembly in 1983, amending N.C. Gen. Stat. §153A-340.

### C. Laws Concerning Business and Employment Practices

As with any business venture, oil and gas development must meet some general prerequisites for conducting business, as established by state and federal law. While most of these considerations are generally applicable to all businesses, such as wage and hour laws and social security, other laws may apply more particularly to offshore oil and gas drilling. These include provisions related to occupational health and safety, certain pricing controls, and special tax provisions.

Since the working conditions on oil rigs are among the most hazardous anywhere, occupational safety and health is a major concern to any company conducting oil and gas drilling activities. The Federal Occupational Safety and Health Act of 1970 (OSHA; 29 U.S.C. §§651-678) applies to workers and workplaces in all states, but §653 excludes working conditions where "other Federal agencies . . . exercise statutory authority to prescribe or enforce standards or regulations affecting occupational safety or health." While Coast Guard occupational safety regulations supersede OSHA, they apply only to Outer Continental Shelf areas and not the three-mile zone.<sup>19</sup> However, some Coast Guard safety regulations regarding inspection of design, equipment, operations, and stability of mobile offshore drilling units are not limited to OCS rigs.<sup>20</sup>

The court cases questioning whether OSHA is superseded by other laws have, to some extent, delineated what OSHA does and does not cover. One case says that "offshore platforms" (with no differentiation between those in federal and state waters) are under Department of Interior and Coast Guard control, so OSHA is not applicable.<sup>21</sup> Similarly, those companies included under the safety regulations of the Natural Gas Pipeline Safety Act of 1968 are exempted from OSHA. Another case states that the Coast Guard has authority over "seamen," but not over onshore workers such as longshoremen.<sup>22</sup> A final case elaborates that non-seafaring offshore activities, such as ship repair, do fall under OSHA regulations.<sup>23</sup>

The Occupational Safety and Health Act of North Carolina (OSHANC, N.C. Gen. Stat. §95-126 et seq.) includes by reference all OSHA provisions and is applicable to most employers and employees in the state. Among those excepted are those protected under the Metal and Non-metallic Mine Safety Act (not applicable to offshore drilling) and those engaged in "maritime operations." State OSHA jurisdiction, according to North Carolina officials, "ends at the

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<sup>19</sup>33 CFR 142 - 174.15.

<sup>20</sup>46 CFR 107.

<sup>21</sup>Marshall v. Nichols, 486 F. Supp. 615 (e.d. Texas, 1980).

<sup>22</sup>Taylor v. Moore-McCormack Lines, Inc., 629 F.2d 88 (4th Cir., 1980); T. Smith & Son, Inc., OSHRC Docket No. 2240, 1974-1975, CCH OSHD ¶18536 (1974).

<sup>23</sup>Petrolane Offshore Construction Services, Inc., OSHRC Docket No. 2361, 1974-1975, CCH OSHD ¶19600, 3 BNA OSHC 1156 (1975).

docks," and therefore does not cover offshore activities. According to federal OSHA officials, however, the state has jurisdiction but may defer to the Coast Guard for occupational safety and health in territorial waters; the Coast Guard can, in turn, defer to the federal OSHA administrators, on a case-by-case basis.

Although price regulations vary with the political climate, they are important for a business to look at in determining whether its operations will be profitable. The Natural Gas Policy Act (15 U.S.C. §3301 et seq.) sets ceiling prices for natural gas from the OCS, from onshore wells, and for use in interstate commerce, among other situations. These price controls are administered by the Federal Energy Regulatory Commission with supporting regulations published at 18 CFR 270 et seq.

Taxation is among the most important considerations of any business. Both federal and state corporate income taxes apply to oil drilling within state waters, and local property taxes apply to onshore support activities, though these taxes are not likely to extend into the water. Under the the North Carolina Income Tax Act of 1939 (N.C. Gen. Stat. §105-130 et seq.) every North Carolina corporation or corporation doing business in North Carolina is subject to a 6 percent tax on net income. Deductions possibly applicable to oil and gas drilling include one for the cost of air cleaning devices, waste treatment facilities, pollution abatement equipment, and the recycling of or resource recovery from solid waste,<sup>24</sup> and one for the use of equipment mandated by OSHA.<sup>25</sup> In addition to income taxes, NRCO is authorized to assess against each barrel of crude oil extracted a tax of up to five mills and against each 1000 cubic feet of natural gas produced, a tax of up to one-half mill, to cover the costs of administering and enforcing the Oil and Gas Conservation Act.

#### D. Laws Concerning Historic and Cultural Preservation

Oil and gas operators drilling in submerged lands may uncover or disturb objects or sites of historical or scientific significance during exploration and development operations. Such finds could include shipwrecks or sites occupied during prehistoric or historic times and since inundated by rising sea levels. Both state and federal laws have been enacted to protect these resources.

Under the National Historic Preservation Act of 1966 (16 U.S.C. §470), the head of any federal department or agency with jurisdiction over or authority to license "a proposed federal or federally assisted undertaking in any State" must, before federal money is spent or a license is issued, "take into account the effect of the undertaking on any district, site, building, structure, or object that is included or eligible for inclusion in the National Register [of Historic Places]." Although only one site within North Carolina waters is listed in the National Register (the U.S.S. Peterhoff near Cape Fear), the criteria for eligibility are rather broad. To be eligible,

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<sup>24</sup>N.C. Gen. Stat. §105-130.10.

<sup>25</sup>N.C. Gen. Stat. §105-130.10A

places may be associated with significant historical events or figures, reflect distinctive characteristics of a particular type or period of architecture or artistic values, or be likely to yield important information on prehistory or history.<sup>26</sup>

Similarly, under N.C. Gen. Stat. §121-12(a), every state agency must consider the effect of any undertaking, including licensing, approval, and authorization, on any site, structure, or object listed in the National Register. If there is any likely effect, the Historical Commission must be given a reasonable opportunity to comment. This statute, unlike its federal counterpart, is limited to those places listed in the Register and does not extend to eligible sites.

N.C. Gen. Stat. §121-22 to §121-28 deals with the salvaging of abandoned shipwrecks and other underwater archaeological sites. The Act vests title to and exclusive dominion and control over all bottoms of navigable waters one marine league (three nautical miles) seaward of extreme low water mark, and all shipwrecks, vessels, and other sea bottom archaeological artifacts unclaimed for over ten years, in the State of North Carolina. The Department of Cultural Resources is custodian of all such vessels, wrecks, and artifacts and is authorized to issue necessary rules and regulations to preserve, protect, recover, and salvage them; these supporting regulations have been promulgated at 7 NCAC 4J.

## II. Permitting, Licensing, and Certification

Offshore oil and gas operations can be divided into four phases. During the first phase, Pre-leasing, geological and geophysical exploration is conducted and measures necessary to acquire a lease for submerged lands may be taken. Once the land has been leased, exploratory drilling, the second phase, commences. If exploratory drilling indicates the presence of commercially sufficient quantities of oil and/or gas, the third stage, Field Development, is undertaken. During this phase, permanent drilling and/or production platforms are built, wells are drilled, and pipelines are laid. After the field has been so prepared, the fourth stage, Production, begins.

The purpose of this section is to list and describe the permits required at each stage and the procedures necessary for obtaining those permits. Since some permits may be required at more than one phase and some may not be required at all, these permits have been categorized as "probable" and "possible" and are listed at the first stage where they might be required. (A tabular description of necessary permits can be found in Table 3-2, at the end of Chapter 3.) Finally, it is important to keep in mind such regulations as the Coast Guard Navigational Safety Standards which are applicable but for which no actual permitting is required.

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<sup>26</sup>36 CFR 60.4.

A. Phase I: Pre-lease

The following permits or approvals are currently required before preliminary exploration begins and/or before a lease is granted:

1. North Carolina Geophysical Exploration Permit (possible)  
N.C. Gen. Stat. §113.27; 15 NCAC 5C

This permit, issued by the Division of Land Resources in the Department of Natural Resources and Community Development, is required for all seismic exploration involving the use of explosives. To obtain the permit, a surety bond of \$5,000 for one crew or \$25,000 for more than one crew must be filed. The Wildlife Resources Commission, the Division of Marine Resources, and the Office of Coastal Management must have an opportunity to review the application. In addition, each crew must be accompanied by a State seismic agent who files a daily report. NRCD, on request, may have access to all records of the explorers, but "only to the extent necessary to determine that all protective requirements have been complied with."

2. Environmental Impact Assessment (EIA) (possible)  
N.C. Gen. Stat. §143B-437

This statute, administered by the Department of Commerce in collaboration with NRCD, requires an assessment of the effects of any new or expanding industry or manufacturing plant on the economic and natural environment of the state. Such assessments, rarely prepared in the past, may be used more often where other environmental impact statements are not required or where the political atmosphere dictates it.

B. Phase II. Exploration

After the land is leased, field exploration is conducted with test drilling to identify potential reservoirs of oil and gas and determine whether it is commercially possible to produce them. The work requires the construction of temporary offshore platforms and small temporary onshore support facilities. The principal environmental effects of these operations were reviewed in Appendix D; they include the dredging and/or filling of access routes, rig discharges, and the risk of oil pollution.

Several of the permits listed here as "possible" are dependent upon the amount of onshore activity accompanying the exploration. Usually land operations, construction and employment are kept at minimal levels at this phase, so many of these permits are not likely to be required in most exploration situations. They are more likely to be required at the Development and Production stages when onshore activity intensifies. The permits applicable to the Exploration stage are as follows:

1. Coastal Area Management Act (CAMA) Major Development Permit (required)

N.C. Gen. Stat. §113A-100 - §113A-128; 15 NCAC 7H, 7J, 7M

A CAMA Major Development Permit will be required before exploratory drilling begins. It is granted by the Office of Coastal Management (OCM) and required for any development in an "Area of Environmental Concern" (AEC) if the activity:

- a. requires permission, licensing, approval, certification, or authorization from the Environmental Management Commission, Mining Control Board, Department of Human Resources, Department of Natural Resources and Community Development, or Department of Administration;
- b. occupies an area in excess of 20 acres;
- c. contemplates drilling or excavating for natural resources; or,
- d. contains a structure(s) covering a ground area of over 600,000 square feet.

AECs have been defined to include:

- a. parts of the estuarine system, including estuarine waters, coastal wetlands, public trust areas, and estuarine shorelines;
- b. ocean hazard areas;
- c. public water supplies; and
- d. natural and cultural resource areas.

To apply for a CAMA Major Development Permit, an application must be submitted to OCM describing the location and type of project, the expected type and area of disposal, construction equipment used, the current and future use of the project area, a specific location map and work plat, and a copy of the deed, lease, or permit to use.

The process for evaluation of requests includes review and comment by appropriate agencies and public notice and comment. The Coastal Resources Commission makes the final decision whether to approve the application based on:

- a. the state guidelines for actions in AECs promulgated under CAMA, which require that permitted activities cannot:
  1. be contrary to coastal management objectives;
  2. present any suitable alternative;
  3. violate air or water quality standards;
  4. present any major or irreversible damage to historic or cultural resources;
  5. measurably increase siltation;

6. create stagnant water bodies;
7. be timed so as to have greater than minimal adverse effect on estuarine life;
8. block navigation; or
9. be inconsistent with the ocean hazard system described at 15 NCAC 7H .300.

(15 NCAC 7H .0208)

- b. local land use plans;
- c. general policy guidelines for the coastal area, listed in 15 NCAC 7M, and including:
  1. Local governments should not unreasonably restrict necessary energy development, but should develop siting measures to minimize impacts on resources.
  2. Impact assessment is required before construction of a "major energy facility," which includes refining facilities, pipelines, and terminal and storage facilities.
- d. other criteria listed in N.C. Gen. Stat. §113A-120 et seq. (including, by reference, §113-229 and §113-230)

The CAMA Major Development Application also serves as a consolidated application for the §10, §404, North Carolina Easement to Fill, and North Carolina §401 Water Quality Certification permits (all described below).

2. National Pollution Discharge Elimination System (NPDES) Permit  
33 U.S.C. §1342; 40 CFR 125.122 et seq.; 15 NCAC 2H .0100. (probable)

This permit is required by the federal Environmental Protection Agency and administered by the North Carolina Division of Environmental Management for point source discharges of drilling muds, industrial wastewater, or domestic sewage from fixed platforms and drillships. To apply, the operator must file with DEM an environmental assessment containing descriptions of:

- a. the proposed new source of discharge;
- b. alternative treatment or other control measures;
- c. primary and secondary environmental impacts;
- d. unavoidable adverse impacts and mitigative measures to address adverse impacts; and
- e. irreversible and irretrievable commitments of aquatic resources.

DEM reviews the application and forwards it for EPA approval. Public notice and a 30-day period for comments are required, with a decision on approval or denial within 90 days. The key question is whether there is any "unreasonable degradation of the marine environment."

3. Section 401 Water Quality Certification  
33 U.S.C. §1341; 15 NCAC 2H .0500 (probable)

This certification by the Division of Environmental Management is required of federally licensed projects with discharges into state waters, to assure that state water quality standards will be met before a federal license or permit is given. The applicant must file with DEM six copies of the following information, to be circulated to the appropriate agencies for comment:

- a. a description of the activity;
- b. the water discharge that is occurring or proposed;
- c. the location of the discharge;
- d. a description of the receiving waters;
- e. a description of waste treatment facilities, if any; and
- f. the names and addresses of adjoining riparian owners.

After a public notice and comment period and possibly a public hearing, the final decision is made by the Environmental Management Commission within 130 days of the application or the hearing.

4. Permit to Drill Exploratory Oil or Gas Wells  
N.C. Gen. Stat. §113-27; 15 NCAC 50 (required)

This permit is required before the drilling of an oil and gas well so that certain regulations regarding well spacing, drilling conduct, protection of groundwater strata, casing, well direction, blowout prevention, plugging, production limits, and abandonment can be met. The permit application must be filed with the Division of Land Resources in NRCD, along with the following information:

- a. the total depth of the well;
- b. the casing program;
- c. proposed boring disposal program;
- d. well name, number, and location;
- e. proof of ownership or leasehold in lands to be drilled;
- f. statement of liability for violation of rules; and
- g. \$50 fee

Permits are usually issued within 30 days. Before drilling exploratory wells, however, the operator must file a \$5,000 bond with NRCD to assure proper plugging of the well.

5. Section 10 Permit for Construction Affecting U.S. Navigable Waters  
33 U.S.C. §401 et seq. (required)

This permit from the U.S. Army Corps of Engineers is required for any excavation, dredging, or dispersal, or the construction of any structure or other impediment to navigation in U.S. navigable waters. In reviewing applications for permits, the Corps consults with affected agencies and considers the effects of the project on:

- a. the public interest;
- b. wetlands;
- c. fish and wildlife;
- d. water quality; and
- e. historic, scenic, and recreational values

Section 10 permits are usually considered together with Section 404 permits and may be granted automatically if State Dredge and Fill, CAMA, and Section 401 permits are issued.

- 6. \$404 Permit (probable)  
33 U.S.C. §1251, §1344; 40 CFR 235

This permit, administered by the Corps, is required for any discharge of dredge and fill materials into navigable waters. Public notice and an opportunity for a public hearing are required. The \$404 permit is usually considered together with the \$10 permit and many of the same environmental standards are applied in the review of both.

- 7. State Air Quality Permit (probable)  
N.C. Gen. Stat. §143-215.108; 15 NCAC 2D, 2H (including national emissions standards for hazardous pollutants)

Issued by the Division of Environmental Management, these permits are required for:

- a. establishing or operating any air contaminant source for which there is an applicable air quality or emission control standard at 15 NCAC 2D or 2H. Such sources include hydrocarbons stored in certain quantities under certain conditions, and may include temporary onshore support bases which store fuel;
- b. constructing, operating, or using any equipment which might emit air contaminants or cause air pollution; or,
- c. constructing or installing any air-cleaning device.

Along with a permit application, detailed engineering plans and specifications are required.

- 8. Prevention of Significant Deterioration (PSD) Permit (possible)  
42 USC §7401 et seq.; 40 CFR 52.21(b)(1)

These permits are administered by the Division of Environmental Management with EPA approval. A permit is required for any new source of air pollution which is located in areas, such as North Carolina coastal counties, which meet National Ambient Air Quality Standards and which:

- a. will emit more than 100 tons per year of a regulated pollutant and is among the sources listed in 40 CFR 52.21(b)(1). (These include oil refineries and petroleum storage units with a

capacity of 300,000 barrels or more; if these facilities are built at all, it will be during field development);

- b. is not listed, but will emit over 250 tons per year of a regulated pollutant.

PSD permits may be processed along with State Air Quality permits (15 NCAC 2H. 0600).

9. Certification of Mobile Offshore Drilling Units (probable)  
46 CFR 107

This regulation requires a certification for safety by the Coast Guard for any mobile offshore drilling units. The Coast Guard has issued detailed safety standards applicable to the design, equipment, operations, and stability of drilling units.

10. State Dredge and Fill Permit (probable)  
N.C. Gen. Stat. §113-229; 15 NCAC 7J .0800-.1024

This permit is required for any project involving dredging and filling in estuarine waters, tidelands, marshlands, or state-owned lakes. Most oil and gas development in the sounds will require dredging and filling to prepare and maintain access to the drill site.

Along with the official permit form, a work plat detailing the proposed construction and mapping its location must be submitted to the Office of Coastal Management. After riparian landowners are given 30 days to comment, there is an on-site investigation and report on the project. All of this information is then circulated to interested state agencies and back for an NRCDD decision within 90 days. The permit application automatically includes a request for a CAMA Major Development Permit, Corps Sections 10 and 404 permits, an Easement to Fill on State-owned Land, and 401 Water Quality Certification, if they are required. A general permit is issued if the state requirements are met and there are no objections submitted by federal agencies.

11. North Carolina Easement to Fill (possible)  
N.C. Gen. Stat. §146-2; 1 NCAC 6B .0500-.0512

This easement will be required if any construction requires filling activities in waters where land is raised above the normal high water mark. At the exploration phase, such construction is unlikely; however, when more onshore facilities are required for support of development and production activities, this easement will more likely be required. Since this filling activity is a real estate action, allowing the alteration and use of state submerged lands, it is administered by the State Property Office in the Department of Administration.

It has become the Department of Administration's practice in recent years to issue these easements only under extraordinary circumstances. Requests to

fill in lands removed by erosion during the previous year are generally approved without an easement, while requests to fill larger areas are generally denied.

12. U.S. Environmental Impact Statement (EIS) (probable)  
42 U.S.C. §4332; 40 CFR 1500-1508.

An EIS is prepared by the lead agency in federal permitting and is required for any action under federal control and responsibility "significantly affecting the quality of the human environment." Activities which require federal permits or licenses are considered to be federal actions for EIS purposes; however, those merely requiring federal review are not. The EIS must go through a public and government comment process and must contain a discussion of:

- a. the environmental impact of the proposed action;
- b. the adverse environmental effects that would be unavoidable if the proposal is implemented;
- c. alternatives to the proposed action;
- d. the relationship between local short-term uses of man's environment and the maintenance and enhancement of long-term productivity; and
- e. any irreversible and irretrievable commitments of resources which would be involved if the proposed action is implemented.

The Corps of Engineers, by virtue of its §10 and §404 permits, would probably act as lead agency and produce the EIS. In Alabama, for instance, the Corps filed separate, sequential EIS's for the initial exploratory wells, for the four additional appraisal wells, and for field development and production in the Lower Mobile Bay gas field discovered and developed by Mobil.

13. State Environmental Impact Statement (SEIS) (possible)  
N.C. Gen. Stat. §113A-4; 1 NCAC 25

A state Environmental Impact Statement, under present law, is required for any proposed legislation or activities "involving expenditure of public moneys for projects and programs significantly affecting the quality of the environment" of North Carolina. Exactly what "public moneys" are has been a subject of dispute; it has been held to include federal and local funds, as well as state funds, but the administrative rules have not been updated to clarify the criteria. Since offshore exploration and drilling do not require state expenditure beyond those costs incidental to permitting and licensing activities, an SEIS may not be necessary. See the discussion of impact statements and SEPA in Chapter 5.

14. Environmental Impact Assessment (possible)  
(see Phase I)

15. Permit for Wastewater Not Discharged to Surface Waters (possible)  
N.C. Gen. Stat. §143-215.3; 15 NCAC 2H

This permit, administered by the Division of Environmental Management (DEM), is required for sewer systems, treatment works, or disposal systems which have over a 3,000 gallon capacity and do not discharge into surface waters. Depending on the amount of waste generated and the type of disposal system used, this may or may not be required. The application submitted, along with design data, specifications and plan information, is assessed by DEM after on-site review by its Water Quality and Ground Water Sections.

16. Solid Waste Disposal Site Permit (possible)  
N.C. Gen. Stat. §130-13B; 10 NCAC 10C

This permit, administered by the Division of Health Services (DHS) in the Department of Human Resources, is required for establishing and operating solid waste disposal facilities and incinerators. To obtain a permit, maps, plans, land ownership and use information, proposed operation procedures and methods, and expected waste generation data must be submitted to DHS.

17. Hazardous Waste Permit (possible)  
N.C. Gen. Stat. §130-13B; 10 NCAC 10F; 40 CFR 260.1-265

This permit, administered by the Department of Human Resources, is required for treatment, storage, or disposal of listed hazardous wastes in North Carolina, including gas and oil drilling muds and oil production brines; most federal regulations concerning hazardous wastes have been adopted by North Carolina. (Non-solid toxic emissions are covered by air and water pollution control regulations and NPDES.) A permit application must include general information about the facility and the company operating it, management processes, operating procedures, security, inspection, contingency plans, and disaster mitigation. After public notice and comment, and possibly a public hearing, a decision is reached within 90 days.

18. Sedimentation Control Plans (possible)  
N.C. Gen. Stat. §113A-50 - §113A-66; 15 NCAC 4

This program has been implemented to reduce the effects of sedimentation in the state's waters and to control accelerated erosion resulting from land-disturbing activities. Thirty days before initiating any land-disturbing activity on a tract of one or more acres, a sedimentation control plan must be filed with the Division of Land Resources. Plans must include architectural and engineering drawings, maps, calculations, assumptions and narrative descriptions of the necessary erosion reduction and sedimentation control structures and devices. Under the act, local governments may take over administration of the program by enacting erosion control ordinances whose standards equal or exceed those of the state.

19. Tax Certification for Resource Recovery, Recycling, or Pollution Abatement Facilities (possible)  
N.C. Gen. Stat. §130-13B, §105-130.10; 10 NCAC 10C .0500

In order to obtain the special tax benefits of installing these facilities, a company must be inspected and certified by the Department of Human Resources.

20. Burning Permits (possible)  
N.C. Gen. Stat. §113-60.21 to §113-60.31; 15 NCAC 9C .0200

These permits, administered by the Division of Forest Resources, are required for certain types of burning related to land clearing activities, particularly in coastal counties. The applicant must also meet any applicable DEM conditions for open burning. These permits can be obtained from the county or district forest rangers.

21. Open Burning Permit (possible)  
N.C. Gen. Stat. §143-215.3; 15 NCAC 2D .0520

This permit, obtained from the Division of Environmental Management, is required for all activities involving open burning, unless specifically exempted. Special permits are required for burning windrows in Beaufort, Bertie, Camden, Carteret, Chowan, Currituck, Dare, Gates, Hyde, Pasquotank, Perquimans, Tyrell, and Washington counties. Application information is provided by the forest ranger when applying for the DFR burning permit (above).

#### D. Phase III. Field Development

After exploratory drilling has indicated the presence of commercial quantities of oil or gas, the field may be prepared for production. During this stage, drilling will continue, and the laying of pipelines, the construction of permanent platforms and wells, and the acceleration of onshore support activities usually also occur. Onshore activities at this stage are likely to include, to some extent, fabrication of pipe and platforms, pipe coating, and the construction of processing facilities, terminals, and refineries, some or all of which will likely require shoreline clearing, dredging, or construction. Some of these uses and activities, such as oil terminals and the laying of pipelines, will occur offshore as well.

With this increased activity come new or increased environmental hazards. In addition to many of the permits mentioned under Phase II above, the following permits may be required:

1. Water Use Permit (possible)  
N.C. Gen. Stat. §143-215.11-.22; 15 NCAC 2E

In areas designated as "capacity use areas" by the Environmental Management Commission (EMC), which include a large portion of coastal North

Carolina, these permits are required for withdrawals of surface water and groundwater in excess of 100,000 gallons of water per day. An applicant for a water use permit must submit an official form to DEM before project initiation and must specify the proposed uses of the water and give some justification for the quantity needed. Processing of the permit, which involves notification of other permit holders if the use is consumptive, usually takes about 30 days. Users are also subject to requirements regarding well-spacing, water level controls, and reporting.

2. Easements Over Water (probable)  
N.C. Gen. Stat. §146-11 et seq.; 1 NCAC 6B .0600-.0610

Easements may be granted for structures over or in navigable waters, including pipelines, which are built to utilize the state's natural resources. A written application must be filed with the State Property Office, with a plat or drawing of the proposed project and a \$100 fee. Applications, which require approval by the Governor and Council of State, are normally processed within 45 to 60 days.

3. Oil Terminal Facility Certificate of Registration (probable)  
N.C. Gen. Stat. §143-215.95 - .98

This permit, administered by the Division of Environmental Management, is required before construction, operation, or substantial modification of any structure used for transferring, transporting, storing, processing or refining oil, including pipelines. The applicant must submit to DEM the name and address of the owner and operator, the principal officers' names, the number of employees, maps, plans, specifications, accident mitigation measures, and an assessment of impacts on fish, wildlife, air, water, and public lands. After completion of the application, circulation to interested agencies, and a public notice, hearing, and comment period, a permit decision will be made. The processing is usually completed in about 160 days. The approved permit, however, is not considered effective until necessary water and air quality permits have been obtained. In addition, the applicable laws require annual reports of facility activity every February 1.

4. Coast Guard Port Adequacy Certificate  
33 U.S.C. §1901 et seq.

Pursuant to the MARPOL Protocol of 1978, relating to the 1933 International Convention for the Prevention of Pollution from Ships, a port or terminal facility needs Coast Guard approval as to its adequacy for the transfer of oil or noxious liquid.

#### E. Phase IV: Production

It is at this point, when offshore drilling structures, onshore terminal facilities, and their linking transportation systems, whether pipelines or tankers, are ready for operation, that oil and gas are brought ashore and processed. Again, this phase may overlap with the exploration and development

stages. The amount of activity at the production stage will vary with the demand for petroleum products in the area. If it is a very high demand area, the oil companies will settle many of their refining and production operations there; otherwise these operations are likely to be located elsewhere. These operations tend to locate where there is a big market for their products, even if this is relatively distant from the source of oil, since it is more expensive to transport finished petrochemical products in all their forms than to transport the unrefined oil.

Again, some of the same permits may be required for production activities as for exploration or development (see Phases II and III above, and Table 3-2). In addition, the following certifications and permits may be required:

1. Public Water Supply Certification (possible)  
N.C. Gen. Stat. §130-13D; 10 NCAC 10D

This certification may be required at the production stage if production reaches a level of activity requiring expansion of the existing public water supply system or construction of a new one. To be certified, a sanitary survey is required for proposed surface or groundwater sources or well sites. In addition, plans, specifications, and engineering reports must be submitted to the Environmental Health Section of the Department of Human Resources.

2. Oil Refining Facilities Permit (possible)  
N.C. Gen. Stat. §143-215.100-.102; 15 NCAC 1F .0001-.0013

A permit is required from the Division of Environmental Management to construct and operate an oil refining facility in North Carolina.

3. Coast Guard Permits and Certifications  
33 CFR 126.27; 46 CFR 154; 49 CFR 176.27

A general permit is required for the handling of dangerous cargo (including liquified petroleum gas and crude oil) at port, if tankers rather than pipelines are used. A certificate of inspection is required for self-propelled vessels carrying bulk liquified gas as well as one for containerized (non-bulk) shipment.

#### F. Additional Considerations

Many of the permits require circulation to, comments from, and/or consultation with other agencies before a permit is granted. This review process is conducted internally in the government and thus requires no additional action on the applicant's part, unless specified. A few of the non-permitting agencies most often consulted are described below.

The Wildlife Resources Commission (WRC) must be consulted if any of the 17 listed endangered or four threatened species of wildlife will be affected by the development. All actions requiring government permits are required to address the impacts on these species prior to issuing a permit. Projects may

be modified, upon WRC recommendation, to preclude any adverse impact on the species or its habitat.

The U.S. Fish and Wildlife Service must be consulted before the permitting of exploratory wells (15 NCAC .0004) and the issuance of federal permits.

The North Carolina Historic Preservation office, within the Department of Cultural Resources, is charged with reviewing all CAMA Permits and all state and federal land disturbing permits. If a property is determined to be historically or archaeologically significant, the effect of the project on the property is assessed, and alternative possibilities, if thought necessary, are suggested.

Under 16 U.S.C. §470f and 30 CFR 60 and 63, the federal Advisory Council on Historic Preservation must be provided a reasonable opportunity to comment on any federal action affecting any "district, site, building, structure, or object that is included or eligible for inclusion in the National Register" of Historic Places. Any federal department or agency, before issuing a license or permit, must consider the effect of the proposed undertaking on these places. The criteria for eligibility (36 CFR 60.4) broadly include any thing or place that may yield important information on prehistory or history.

Finally, under the federal Coastal Zone Management Act and North Carolina Executive Order #15, consistency certification is required from the state before any federal permitting or state action, to assure that the proposed action is consistent with the state's coastal program.

One last consideration is the effect of local legislation, regulation, or zoning in the area of activity. Pursuant to state law, local governments may adopt land use plans which could affect oil and gas production; in coastal areas, CAMA requires that local plans classify all land as "developed," "transition," "community," or "conservation," and that any CAMA development permits be consistent with these plans. In addition, the General Assembly has recently passed legislation authorizing counties to regulate development in estuarine waters and public trust lands under navigable waters; this act may significantly increase the role of local government in regulating oil and gas activities (see Chapter 5). Under state law, local governments may also require environmental impact assessments (N.C. Gen. Stat. §113A-8) enact stricter erosion control ordinances than the State's (§113A-54), and enact ordinances and regulations regarding oil pollution control (§143-215.82). All of these possibilities should be considered prior to activity in the area.

## APPENDIX F

### Lease Form for Oil and Gas Mining in Submerged Lands

#### Introduction

The following "model lease" is an attempt to expose the reader to the necessary provisions of an oil and gas lease and to various options for drafting these provisions. In some sections, the clauses currently used in North Carolina leases are compared to those of other states. In others, a single clause, felt to be the best example, is presented and discussed.

In deciding which form of lease to adopt, several factors come into play. First, the bargaining power of the parties should be considered in light of the prospects for discovery of oil or gas. In states such as Texas, with proven reservoirs of offshore oil, the state is in a superior bargaining position compared to states like North Carolina, where the existence of reserves is speculative. A second and related consideration is the fairness of the provisions to the parties; the state should arguably take the upper hand, but not to such an extent as to completely dominate the lessee's activities. Finally, the controlling consideration should be the best interest of all the citizens of the state; the lease should therefore reflect a balance between the energy, environmental, commercial, and recreational concerns of the people of North Carolina.

North Carolina Oil and Gas Lease

This AGREEMENT, made and entered into this \_\_\_\_\_ day of \_\_\_\_\_, 19\_\_\_\_, by and between the STATE OF NORTH CAROLINA, acting by and through the North Carolina Department of Administration and the North Carolina Department of Natural Resources and Community Development, the State hereinafter designated as the "Lessor," and \_\_\_\_\_, hereinafter designated as the "Lessee."

WITNESSETH

THAT WHEREAS, the North Carolina Department of Administration has recommended to the Governor and Council of State the leasing of certain mineral interests in the properties hereinafter described; and

WHEREAS, the North Carolina Department of Natural Resources and Community Development, hereinafter referred to as "Department," has recommended and approved the leasing of certain mineral interests in the properties hereinafter described; and

WHEREAS, the Governor and Council of State of North Carolina at a meeting held in the City of Raleigh, North Carolina, on the \_\_\_\_\_ day of \_\_\_\_\_, 19\_\_\_\_, approved this lease agreement and directed the execution thereof; and

WHEREAS, the Lessee desires an exclusive lease covering certain mineral deposits within the area hereinafter described, to wit: Oil, and gas; and

WHEREAS, the party of the first part is fully authorized and empowered to enter into and execute this lease agreement pursuant to GS 146-8 of the North Carolina General Statutes.

NOW, THEREFORE, for and in consideration of \_\_\_\_\_ to it in hand paid, the receipt of which is hereby acknowledged, together with the covenants and agreements of Lessee hereinafter set forth, which are to be paid, kept and performed by Lessee and which are made conditions precedent to the continuance of this lease, Lessor has leased and by these presents does lease unto Lessee in the below described area the exclusive right and privilege to drill for, mine, extract, remove and dispose of oil and gas in or under the following described area of the submerged lands of the State of North Carolina to which the State is authorized to make leases by authority of GS 146-8 of the North Carolina General Statutes; to wit: [description]

Said land, hereinafter referred to as the leased area, is estimated to comprise \_\_\_\_\_ acres, whether it comprises more or less.

[Comments]

The amount of consideration has been left blank, although North Carolina has in the past asked for a nominal one dollar. The current prevailing

practice is to include a "bonus" payment as consideration for the execution of the lease. This amount varies widely depending on the prospects for and success in the particular area. It should be more than a nominal amount to avoid any legal challenge as to whether the lessee is a "bona fide purchaser for value" who has acquired a definite property interest.

The above Preamble corresponds with the leasing procedures historically practiced in North Carolina. If this procedure is changed, the Preamble may require alteration and clarification of the process used for granting the lease. Thus, the parties' signatures on the lease will indicate that the correct procedures were followed, avoiding potential challenges on this issue. If a competitive bidding process is adopted, the following wording, based on Texas and Louisiana leases, may be used:

WHEREAS, pursuant to North Carolina General Statutes \_\_\_\_\_, and subject to all rules and regulations promulgated by the North Carolina Department of Administration and Department of Natural Resources and Community Development (hereinafter, "Department") pursuant thereto, and all other applicable statutes and amendments to said General Statutes, the State of North Carolina, hereinafter referred to as "Lessor," advertised for bids for a lease covering oil, gas, and other liquid or gaseous minerals in solution and produced with oil or gas on the property described below; and

WHEREAS, in response to required advertisements, bids were received and duly opened and considered in the City of Raleigh, Wake County, State of North Carolina, on the \_\_\_\_\_ day of \_\_\_\_\_, 19\_\_\_\_, at a meeting of the \_\_\_\_\_ [controlling board, commission, or agency] of the State of North Carolina; and

WHEREAS, the \_\_\_\_\_ [controlling board] accepted the bid of \_\_\_\_\_ whose mailing address is \_\_\_\_\_, hereinafter referred to as "Lessee," as being the best and highest [or, "most advantageous"] to the State of North Carolina.

NOW THEREFORE, [same as above]

Section 1: Rights of Lessee. In addition to the exclusive rights and privileges set out above, Lessee has:

- (a) the nonexclusive right to conduct within the leased area geological and geophysical explorations in accordance with applicable regulations;

[Comment]

This subsection may be included, alternatively or additionally, under Section 2: Reservations to Lessor, as a right which may be granted to other parties by the State.

- (b) the nonexclusive right to drill water wells within the leased area, unless the water is part of geopressured-geothermal and associated resources, and to use water produced therefrom for operations free of cost, provided that such drilling is conducted in accordance with procedures approved by the Department; and
- (c) in the event it becomes necessary for the full enjoyment of the rights granted by this lease, Lessee may apply to Lessor for easements and permits to construct or erect and to maintain within the leased area all platforms, fixed or floating structures, sea walls, docks, dredged channels and spaces, buildings, plants, telegraph or telephone lines and cables, pipelines, reservoirs, tanks, pumping stations and other works and structures. Approval of such easements and permits shall not be unreasonably withheld.

Section 2: Reservations to Lessor. All rights in the leased area not expressly granted to Lessee by this lease are hereby reserved to Lessor. Without limiting the generality of the foregoing, such reserved rights include:

- (a) Geological and geophysical exploration; rights-of-way. The right to authorize the conduct of geological and geophysical exploration in the leased area which does not interfere with or endanger actual operations under this lease, and the right to grant such easements or rights-of-way upon, through, or in the leased area as may be necessary or appropriate to the working of other lands or to the treatment and shipment of products thereof by or under authority of the State of North Carolina, its Lessees or Permittees.
- (b) Leases on other minerals. The right to grant leases for the extraction of any minerals or products other than oil and gas within the leased area or any part thereof. No lease of other minerals or products shall authorize or permit the Lessee thereunder unreasonably to interfere with or endanger operations under this lease.

Section 3: Term. This lease shall continue for a period of \_\_\_\_\_ years, hereinafter the "primary term," from the effective date of this lease and so long thereafter as oil or gas may be produced in paying quantities from the leased area or areas pooled therewith, or so long as this lease is held in force by drilling or well reworking operations or as otherwise provided for hereinafter, and as approved by the Department.

[Comments]

Most states have a primary term of three to five years, though California has a twenty year term. The shorter the primary term, the sooner the Lessee will be encouraged to commence operations; however, an area in which little exploration has been conducted may need a longer term so that preliminary surveying can be done.

Production in "paying quantities" may need some further definition. Therefore, a "Definitions" section should be included in the lease to clarify this and other possibly ambiguous terms.

Section 4: Rental.

Option 1: Lessee agrees to pay Lessor on or before the first day of each primary term year commencing prior to a discovery of oil or gas on the leased area, a rental of \_\_\_\_\_ per acre or fraction thereof. Provided, however, if Lessee drills, participates in the drilling of, or causes to be drilled, one or more exploration wells that reach basement rock, as determined by the Department, in each area described herein, the annual rent paid for the year in which the exploration well, or wells, was drilled will be returned to Lessee. Provided further, in the event Lessee's lease area consists of more than one lease block, as herein described, it is understood and agreed that the drilling of one exploratory well to basement rock will serve to fulfill all drilling requirements herein stated, and will qualify the Lessee to receive a return payment of all rents paid on up to ten (10) individual lease blocks for the year in which the exploratory well, or wells, was drilled. This repayment of rents provision applies only to the first and second year of the original primary term.

[Comment]

This option, the current North Carolina provision, is an example of a "drill or pay" lease, making payment of delay rentals an obligation of the lessee, and allowing the lessor to either take legal action for breach of contract or terminate the lease if the lessee does not pay its rental payment

for the given year. This option requires payment of rental after the second year, even if drilling occurs, giving the lessee initiative to start operations and avoid payments early in the lease, but not to continue them. This may lead to rushed operations which may not be as productive as better planned ones. The power that this provision gives the lessor is somewhat diminished by the clause usually included in the lease giving lessee the right to surrender all or any portion of its lease at any time. The "drill or pay" form of rental is no longer widely used.

Option 2: The Lessee shall pay to the State annually in advance, rental of \_\_\_\_\_ dollars (\$ \_\_\_\_\_) per year for the first three years of the lease. Thereafter, rental shall be one dollar (\$1) per acre per year and shall be payable annually in advance. If any portion of the leased lands is quitclaimed as to all zones, the annual rental shall be reduced one dollar (\$1) for each acre quitclaimed with the reduction effective on the lease anniversary date next following the date of quitclaim. However, under no circumstances, including quitclaim of all or any part of the leased lands, shall there be any reduction in the rental obligation for the first three years.

[Comment]

This provision is used in California, where the rental is ten million dollars per year for the first three years of a twenty year lease. The amount of payment should depend on the prospective value of the particular tract. This provision guarantees the state substantial payments because the first three years are a fixed payment, regardless of operations on the lands or surrender of all or part of the lands. Because of this fixed payment, however, there is little incentive for the lessee to begin operations during this period.

Option 3: If actual drilling operations are not commenced on the leased area in good faith on or before one year from the date hereof, this lease shall terminate as to both parties unless Lessee on or before the expiration of said period shall pay or tender to Lessor the sum of \_\_\_\_\_ dollars (\$ \_\_\_\_\_) (hereinafter called "rental"), which shall extend for one year the time within which actual drilling operations may be commenced. Thereafter, annually, in

like manner and upon like payments or tenders, the commencement of actual drilling operations may be further deferred for successive periods of twelve (12) months each during the primary term. Payment or tender of rental may be made by check or draft of Lessee made payable to the order of The State of North Carolina and mailed or delivered to the North Carolina State Treasurer, on or before the rental payment date.

[Comment]

This provision, known as an "unless" clause, is the one most commonly used. It gives the lessee some incentive to begin operations early, to avoid payments and make money for itself as well. This option favors the lessee more than the lessor, since the only result of failure to drill or pay is termination of the lease, and there can be no action for breach of contract as in Option 1. While the term "actual drilling operations" may be vague, it can be better defined in this clause or in a separate lease section of definitions. While Alabama combines its rental provision with the Extension of Term section in its standard lease, other states do not; this combination is probably not advisable. This clause may be altered, as in Texas, to require payment on a "per acre" basis.

Option 4: Rentals.

- (a) Lessee shall pay annual rental to the State in accordance with the following rental schedule:

- (1) for the first year, \$1.00 per acre or fraction of an acre;
- (2) for the second year, \$1.50 per acre or fraction of an acre;
- (3) for the third year, \$2.00 per acre or fraction of an acre;
- (4) for the fourth year, \$2.50 per acre or fraction of an acre;
- (5) for the fifth year and following years, \$3.00 per acre or fraction of an acre; provided that the State may increase the annual rental rate as provided by law upon extension of this lease beyond the primary term.

- (b) Annual rental paid in advance is a credit on the royalty or net profit share due under this lease for that year.

- (c) Lessee shall pay the annual rental to the State of North Carolina (or any depository designated by the State with at least 60 days' notice to Lessee) in advance, on or before the annual anniversary date of this lease. The State is not required to give notice that rentals are due by billing Lessee. If the State's (or depository's) office is not open for business on

the annual anniversary date of this lease, the time for payment is extended to include the next day on which that office is open for business. If the annual rental is not paid timely, this lease automatically terminates as to both parties at 11:59 p.m., Eastern Standard Time, on the date by which the rental payment was to have been made.

[Comment]

This provision from Alaska's standard lease is probably the best alternative from the state's perspective. It guarantees the state some revenue, unlike options 1 and 3, but it also provides a strong incentive for the lessee to begin operations as soon as possible, since each year of delay will cost significantly more than the preceding year. Rental per acre and increments of increase can be varied; Florida, for example, does not begin raising the rental price until after two years. Likewise, the provision for automatic termination may be amended to comply with the state's policy.

Section 5: Royalties on Production.

A. Royalty Payments.

Option 1: In the event oil or gas is produced by Lessee in paying quantities from the leased premises, Lessee will develop and operate such oil or gas field so as to continually produce and save oil or gas therefrom, all in a reasonable and prudent manner according to sound economic principles and practices and will make payments as follows:

1. For all oil produced and saved from the leased premises, Lessee will pay to Lessor one-sixth (1/6) of the market price at the well for oil of like grade and gravity prevailing on the day such oil is run into the pipelines or into field storage tanks.
2. For the gas from each well, where only gas is found, Lessee will pay to Lessor one-sixth (1/6) of the market price at the well for gas produced from any well and used by Lessee off the premises. For gas produced from any oil well and used off the premises or for the manufacture of casinghead gasoline, Lessee will pay to the Lessor one-sixth (1/6) of the market price at the well for the gas so used.

[Comment]

This option, the current North Carolina provision, has the benefit of simplicity and straightforwardness; however, this simplicity may lead to

unnecessary confusion in interpretation. Exactly which types and uses of oil and gas command royalties and how market price is determined need clarification. Since all oil and gas production is to be charged the same percentage royalty payment, the separate provisions for oil and gas might be consolidated to say "operations under this lease," with some elaboration of how market price is determined.

Option 2: When production of oil and/or gas is secured, Lessee agrees to pay or cause to be paid to Lessor, as follows:

1. Oil: As a royalty on oil, which is defined as including all hydrocarbons produced in a liquid form at the mouth of the well and also all condensate, distillate, and other liquid hydrocarbons recovered from oil or gas run through a separator or other equipment, as hereinafter provided, \_\_\_\_\_ part of the gross production or the market value thereof, at the option of the Lessor, such value to be determined by (1) the highest posted price, plus premium, if any, offered or paid for oil, condensate, distillate, or other liquid hydrocarbons, respectively, of a like type and gravity in the general area where produced and when run, or (2) the highest market price thereof offered or paid in the general area where produced and when run, or (3) the gross proceeds of the sale thereof, whichever is the greater. If no other oil is produced in the general area, value shall be determined by the highest gross price paid or offered the producer. Lessee agrees that before any gas produced from the land hereby leased is sold, used or processed in a plant, it will be run free of cost to Lessor through an adequate oil and gas separator of conventional type, or other equipment at least as efficient, to the end that all liquid hydrocarbons recoverable from the gas by such means will be recovered. Upon written consent of Lessor, the requirement that such gas be run through such a separator or other equipment may be waived upon such terms and conditions as prescribed by Lessor.

2. Non-Processed Gas: As a royalty on any gas (including flared gas), which is defined as all hydrocarbons and gaseous substances not defined as oil in subsection (1) above, produced from any well on said land (except as provided herein with respect to gas processed in a plant for the extraction of gasoline, liquid hydrocarbons or other products) \_\_\_\_\_ part of the gross production or the market value thereof, at the option of Lessor, such value to be based on the highest market price paid or offered for gas of comparable quality in the general area where produced and when run, or the gross price paid or offered to the producer, whichever is the greater.

3. Processed Gas: As a royalty on any gas processed in a gasoline plant or other plant for the recovery of gasoline or other liquid hydrocarbons, \_\_\_\_\_ part of the residue gas and the liquid hydrocarbons extracted or the market value thereof, at the option of Lessor. All royalties due herein shall

be based on one hundred percent (100%) of the total plant production of residue gas attributable to gas produced from this lease, and on fifty percent (50%) or that percent accruing to Lessee, whichever is the greater, of the total plant production of liquid hydrocarbons, attributable to the gas produced from this lease; provided that if liquid hydrocarbons are recovered from gas processed in a plant in which Lessee (or its parent, subsidiary or affiliate) owns an interest, then the percentage applicable to liquid hydrocarbons shall be fifty percent (50%) or the highest percent accruing to a third party processing gas through such plant under a processing agreement negotiated at arms' length (or if there is no such third party, the highest percent then being specified in processing agreements or contracts in the industry), whichever is the greater. The respective royalties on residue gas and on liquid hydrocarbons shall be determined by (a) the highest market price paid or offered for any gas (or liquid hydrocarbons of comparable quality) in the general area or (b) the gross price paid or offered for such residue gas (or the weighted average gross selling price for the respective grades of liquid hydrocarbons), whichever is the greater. In no event, however, shall the royalties payable under this paragraph be less than the royalties which would have been due had the gas not been processed.

4. Other Products: As a royalty on carbon black, sulphur or any other products produced or manufactured from gas (excepting liquid hydrocarbons) whether said gas be "casinghead," "dry" or any other gas, by fractionating, burning or any other processing, \_\_\_\_\_ part of the gross production of such products, or the market value thereof, at the option of Lessor, such market value to be determined as follows:

- a. on the basis of the highest market price of each product, during the same month in which such product is produced, or
- b. on the basis of the average gross sale price for each of the products for the same month in which such products are produced; whichever is the greater.

5. No Deductions: Lessee agrees that all royalties accruing to Lessor under this lease shall be without deduction for the cost of producing, gathering, storing, separating, treating, dehydrating, compressing, processing, transporting, and otherwise making the oil, gas and other products produced hereunder ready for sale or use.

[Comment]

This subsection, excerpted from the Texas Standard Lease, gives more detailed definitions of oil and gas. It also assures the lessor the benefit of the highest possible calculation of the market value. While this method may be the most beneficial to the state, it requires a lot of record keeping and calculation on the part of the lessee. Some of the provisions,

particularly that the product be delivered to the state at the lessee's expense and that there be no deductions for production costs, are standard with proven reservoirs of oil and gas. In North Carolina's situation, it may be advisable to lower the royalty share in consideration of these expenses, or to adopt a net profit share form of payment (see Section 6: Share of Net Profit). The alternatives for payment in kind or in value can be included in these provisions, as done here or as a separate provision.

Option 3: Royalty shall be as follows:

(a) On oil (which includes condensate and other liquid hydrocarbons): 20% of the market value at the well as hereinafter defined of all oil produced and marketed hereunder and not used for fuel in conducting operations on the land leased hereunder or pooled herewith or in treating to make marketable the products therefrom. Market value for oil is hereby defined as the current posted price for oil of like grade and quality currently prevailing in that field on the date it is run into the pipeline, barge, or other conveyance used in transporting oil from the well, without any deductions whatsoever except applicable severance taxes paid on production and processing costs, as defined in subsection (c) hereinafter. In the event no posted price exists in the field, then the average of the posted price of oil of like grade and quality currently prevailing in the three nearest offshore fields of similar size shall be used to compute market value in accordance herewith.

(b) On gas (including casinghead gas or other gaseous substances produced and saved from said land):

(1) On gas in its natural state or otherwise, not sold but rather utilized off the premises by Lessee for purposes other than the recovery, extraction or manufacture of gasoline or other products therefrom, 20% of the market value of the gas at the well.

(2) On gas marketed in its natural state or otherwise, 20% of the net proceeds received by Lessee from such sale; and if processed by an unaffiliated third party on behalf of Lessee for the recovery, extraction or manufacture of gasoline, sulphur or other products therefrom in any plant, 20% of the proceeds received by Lessee (i) under the agreement of contract governing such processing on behalf of Lessee, or (ii) from the sale by Lessee of the products delivered or allocated to Lessee thereunder, subject to Lessor's rights to review any gas contract as hereinafter provided in (b)(5) below.

(3) On gas processed by Lessee itself or any of Lessee's wholly or partially owned affiliates or subsidiaries for the recovery, manufacture or extraction of gas, gasoline, sulphur or other products therefrom in any plant: (i) 20% of the net proceeds derived from the sale of such gas, gasoline, sulphur or other product so recovered, extracted or manufactured, or (ii) at

Lessor's election 20% of the gasoline, sulphur or other products in kind, so recovered, extracted or manufactured, and 20% of the net proceeds at the outlet side of such plant of any residue gas, subject to sales contract review by Lessor as hereinafter set forth in (b)(5) below. In the event of Lessor's election to take in kind its 20% share of the gasoline, sulphur or other products so recovered or manufactured, Lessor shall be charged its proportionate share of the direct cost and expenses of recovering, extracting and manufacturing such gas, gasoline, sulphur or other products. Nothing herein shall be construed as obligating Lessee to recover, extract or manufacture gasoline, sulphur or other products in any plant.

(4) "Net proceeds" as used herein shall be defined as the proceeds remaining after deducting from the sales price received under any bonafide contract for sale of gas, gasoline, sulphur or other products applicable severance tax and processing costs, as defined in subsection (c) hereinafter.

(5) Upon entering any gas sales contract, Lessee shall submit said contract to Lessor who shall have six months to elect to ratify said contract and be governed by its provisions or to reject said contract, market or process its own gas, and by so doing release Lessee from its obligations to market hereunder. Failure to take any action shall constitute ratification of the contract. By ratifying the contract, Lessor agrees to accept all clauses in the contract including the pricing provisions thereof.

(6) Nothing contained in this lease shall be interpreted as limiting the right of Lessor to take its gas royalty in kind; provided, however, the election to take gas royalty in kind is a one time election which the Lessor must elect within the above described six-month period (see (b)(5) above) or forever waive its right to take in kind the gas which is the subject of such contract so ratified by Lessor. Failure to make an election shall constitute an election not to take in kind.

(c) In all cases under paragraphs (a) and (b) hereinabove wherein Lessee is allowed to deduct certain specified costs from the amounts due Lessor as royalty, such deductions are hereby termed to be "processing costs." Processing costs shall mean all of the cost and expense incurred in connection with transporting, compressing, and treating to make marketable the minerals covered by this lease from the time they are produced at the wellhead until the products extracted therefrom are ready for sale at the tailgate of any treating facility. Such processing costs shall be limited to the following items: (1) cost incurred in transporting the mineral from the wellhead to any treating facility; (2) direct operating cost for stabilization, sulphur recovery, compression and gas treating, and overhead directly related to the processing of the minerals taken from the leased premises; and (3) depreciation on the facilities used for transporting the minerals, stabilization, sulphur recovery, compression and gas treating, at a rate not to exceed ten percent (10%) per annum based upon the useful life of the facility and the gross investment therein of the Lessee, subject to the limitations set forth hereinafter.

In no event shall processing costs, including depreciation costs, include any profit on processing operations or return on capital investment. All of

the processing costs specified in subparagraphs (1), (2) and (3) above will be on an actual year's experience basis. At the end of each year, the costs will be tabulated, and if there is any overpayment by Lessor, the same will be repaid by Lessee within sixty (60) days; if there is any underpayment by Lessor, the same will be deducted from future royalty. Any fuel from the well stream used in processing attributable to the Lessor's royalty interest share of the minerals, will be provided free of charge from royalty obligation.

All depreciation and processing costs will be calculated on a prorata basis for the total production of the plant and will be allocated back to the share of production attributable to Lessor's royalty and shall be limited to that percent of the total plant production attributable to production under this lease.

Lessee shall provide, on a monthly basis, a recapitulation depicting all costs, including processing and depreciation costs, deducted from Lessor's royalty.

Nothing expressed or implied by this lease shall obligate Lessee to transport or process minerals produced under this lease.

[Comment]

This option, from the Mississippi lease, combines methods for calculating royalties by using a strict "market value" basis for oil and for gas used by lessee, and a "net proceeds" basis for gas sold by lessee. This option thus allows recovery of royalties based on the sale price for substances sold and based on the prevailing price for substances used or stored for later sale, giving the state its proportion of the value at the time of extraction. Further, it allows deductions from these amounts for severance taxes and costs of production. This detailed option is arguably the fairest, though it may be more lengthy than desired.

Option 4: In the event oil or gas is produced by Lessee in paying quantities from the leased premises, Lessee will develop and operate such oil or gas field so as to continually produce and save oil or gas therefrom, all in a reasonable and prudent manner according to sound economic principles and practices and will make payments as follows:

1. For all oil produced and saved [or sold] from the leased premises, Lessee will pay or cause to be paid to the Lessor \_\_\_\_\_ part of the market value at the well for such oil. Oil is defined as including all hydrocarbons produced in a liquid form at the mouth of a well and also all condensate, distillate, and other liquid hydrocarbons recovered from oil or

gas run through a separator or other equipment and shall include, for royalty purposes, that oil used for fuel in conducting operations on the land leased hereunder or pooled herewith or in treating to make marketable the products therefrom. Market value is defined as the current posted price for oil of like grade and quality prevailing in that field on the day it is run into the pipeline, barge, field storage tank, or other conveyance used in transporting or storing oil from the well. In the event no posted price exists in the field, the average of the posted price of oil of like grade and quality currently prevailing in the three nearest offshore fields of similar size shall be used to compute market value. [If neither of these two methods is practicable, market value at the well can be determined by the net proceeds received by Lessee from the sale of such oil.]

2. For the gas from each well, where only gas is found, Lessee will pay or cause to be paid to Lessor \_\_\_\_\_ part of the market value at the well for gas produced from any well and used by Lessee [or other parties] off the premises, the market value of gas being calculated in the same way as described for oil in subsection one (1) above. Gas is defined as all hydrocarbons and gaseous substances which are not defined as oil in subsection one (1) above.

3. For gas produced from any oil well and used off premises by Lessee [or other parties], or used for the manufacture of casinghead gasoline, Lessee will pay or cause to be paid to Lessor \_\_\_\_\_ part of the market value at the well for the gas so used, the market value being calculated in the same way as described for oil in subsection one (1) above.

[Comment]

Making these minor modifications to the current North Carolina provision may be the best option. Better definitions of oil, gas, and "market value at the well," as included here, should make the clause adequate. The survey of other states' lease forms indicated varying categorization of the gas discovered, according to type of well, processing procedures, or type of user. This provision has been drafted to reflect the current North Carolina lease distinctions; using different classifications, or no classifications at all (as in Option 3), should be considered before adopting a royalty clause.

Certain portions of this option have been bracketed to indicate that they are optional. The provision regarding net proceeds provides a last choice alternative for calculating market value, though it may raise more problems, in deciding when to use this method, or what "net proceeds" covers, than it

settles. If this clause is adopted, a clause regarding deduction of the costs of production should be considered (see Options 2 and 4). The "or other parties" and "or sold" sections have been bracketed because it is unclear whether or not the intent of the existing royalty clause is to charge royalties on oil and gas sold to or used by parties other than the lessee. It is usually the case that royalties are not charged for oil and gas used on the premises for drilling operations and that they are charged for products sold. Although this intent is implied by references to royalties only on oil "saved" or gas used off premises, it might be advisable to include an explicit statement to this effect in this section or elsewhere.

B. Payment in Kind

Option 1: In lieu of monetary payments as provided for in Subsection A above, Lessor may at any time, and from time to time, with sixty (60) days written notice to Lessee elect to receive in kind its royalty share of oil and/or gas for the subsequent payment period as described in Subsection D below. Such royalty share shall be delivered to Lessor or the Lessor's credit into field storage tanks or pipelines as designated by Lessor, at Lessor's sole cost and expense. Title to such royalty share shall pass at the point of delivery to Lessor. Lessor's royalty share shall be computed as the same proportionate share(s) of oil and/or gas agreed upon in Subsection A above, as produced and delivered into Lessee's field storage tanks or pipelines during the same period.

[Comment]

An "in kind" clause is a standard part of an oil and gas lease. This one is drawn from the existing North Carolina lease, with a few alterations. The notice period has been changed from thirty to sixty days to conform to the provisions of most other states. The period for which payment may be made in kind has been clarified to extend for a full one-month period, as opposed to the existing clause which could conceivably allow confusing fluctuation between monetary and in kind payment on a daily basis. The payment period (see Subsection D below) has been changed from two months to one month, so

that in kind payments will last for a one-month minimum and the option may be re-exercised each month. Some states, including Florida and Mississippi, allow exercise of this option only once a year for a full year period.

Option 2: Lessor shall have the option to take in kind its royalty on oil at any time upon Lessor giving Lessee 90 days written notice to that effect. The acceptance by Lessor of a royalty other than in kind shall not be construed as a waiver of Lessor's option to take its oil royalty in kind at later dates or times. Upon 90 days written notice to Lessee, Lessor may revoke such election so as to again require Lessee to handle and dispose of Lessor's share of all oil royalty. Provided, however, no option by Lessor hereunder shall be exercised at time intervals of less than one year, so that once an election is made and executed, the option hereunder cannot be again exercised for a period of at least one year. Lessor's portion of oil produced when Lessor elects to take in kind shall be delivered to Lessor at Lessor's option either (1) into Lessor's field storage facilities, or (2) to Lessor's credit into any pipeline or other facility into which the oil is delivered to a purchaser.

[Comment]

This alternative payment-in-kind clause requires no notice to continue in-kind payments once the option has been invoked. Rather, it requires the lessor to notify the lessee to return to payment of monetary royalties. This clause also permits the lessor only to invoke the in-kind option once per year, for a full year period, thereby saving the parties from the confusion of switching payment form too often.

There are other alternative clauses for the "in kind" section. One might be to cause the lessee to incur some of the expenses of delivery or storage, particularly those corresponding to any nondeductible expenses which would occur if payment by lessor was received in value rather than in kind. Another way of drafting this provision would be to include it in the same subsection that describes royalty payments (see Subsection A, above).

C. Standard Measurement of Gas and Oil

The standard units of measurement in determining payments under subsections A and B above are the stock tank barrel and the standard unit of gas as defined by the American Petroleum Institute as follows:

1. The stock tank barrel shall equal 42 U.S. gallons at 14.65 psi and 60 degrees Fahrenheit;
2. The standard unit of gas shall be the cubic foot measured at 14.65 psi and 60 degrees Fahrenheit.

All meters and measuring devices used in handling produced oil and/or gas under the terms of this lease shall be calibrated to the standards set forth in this paragraph.

[Comment]

This important subsection may alternatively be included in the definitions of oil and gas in Subsection A above. However, listing these standards within Subsection A might only serve to make it more confusing.

D. Payment of Royalties

All royalties not taken in kind shall be made by check or draft of Lessee, drawn to the order of the State of North Carolina and mailed or delivered to the office of the North Carolina State Treasurer in Raleigh, North Carolina, on or before the 15th day of the second month next following the month of production. Each payment shall be accompanied by the affidavit of Lessee, or Lessee's authorized agent, showing (1) the gross amount of production, (2) disposition, and (3) the gross sales value or proceeds received, of all oil, gas or other liquid or gaseous hydrocarbon mineral, and their respective constituent products, produced from the leased area or acreage pooled therewith. Lessee shall retain for not less than two (2) years a copy of all documents, records or reports confirming the gross production, disposition and gross sales values or proceeds received, including gas meter readings (corrected to standard temperature and pressure), pipeline receipts, gas line receipts, and other checks or memoranda of amount produced and put into pipelines, tanks or pools and gas lines or gas storage, all gas contracts (whether for sale or process) and amendments thereof, and any other reports or records which the State Lands Division may require to verify said gross production, disposition and gross sales values or proceeds received; and all such records shall at all times be subject to inspection and examination by the Secretary of the Department of Natural Resources and Community Development of North Carolina or his duly authorized representative. Lessee shall bear all responsibility for paying or causing all royalties to be paid as prescribed by the due date provided herein.

[Comment]

This provision, taken from the Alabama standard lease, is more complete than the existing North Carolina provision. This conforms with the prevailing practice of requiring monthly payment of royalties and submission of supporting documents, as opposed to the existing North Carolina bimonthly requirement.

E. Minimum Royalty

Option 1:

At the expiration of each lease year commencing after discovery of oil or gas, or after the expiration of the primary term of this lease, if this lease is maintained by production, the royalties paid to Lessor in no event shall be less than an amount equal to the total annual delay rental herein provided for in Section 4; otherwise, there shall be due and payable on or before the last day of the month succeeding the anniversary date of this lease a sum equal to the total annual rental less the amount of royalties paid during the preceding year.

[Comment]

A minimum royalty provision is important as both an incentive for the lessee to continue productive and profitable operations and as a guarantee of payment to the lessor. This option, based on the Texas provision, states the requirement for minimum royalties in a simpler manner than the existing North Carolina clause. While this clause provides for minimum royalties equal to delay rentals, other states provide for larger minimum royalties, sometimes twice the delay rental. The amount charged depends on the size of the prescribed delay rentals, the prospects for profitable production, and the overall bargaining power of the state. In the case of North Carolina, with undetermined reservoirs of oil and gas, both delay rentals and minimum royalties should remain relatively low.

Option 2:

The minimum amounts payable under this lease for each lease year shall be, in any event, not less than \$ \_\_\_\_\_ per lease year, if during the primary term, and not less than \$ \_\_\_\_\_ per lease year, if after the expiration of the primary term of this lease, which amount shall be called "minimum royalty". If for any such lease year the accrued royalty plus any delay rentals (where the lease is still in the primary term) or shut-in well royalties that have been paid for such lease year equals or exceeds the minimum royalty, then the terms of this paragraph shall not apply. If, however, for any such lease year the accrued royalty, together with any amounts paid as delay rentals or shut-in well royalties is less than the minimum royalty, then Lessee shall within sixty (60) days following the close of such lease year, pay or tender to Lessor, as prescribed in Section 5D above, the difference between the minimum royalty and an amount equal to the accrued royalty plus any delay rentals and shut-in well royalties paid for such year.

[Comment]

This option provides for a minimum royalty in an amount different from the delay rental for years within the primary term, guaranteeing payment during the primary term even if drilling operations are undertaken. Such a provision is inadvisable as an unnecessary complication of rental payments during the primary term. Otherwise, it is similar in effect to Option 1, except for the inclusion of shut-in well royalties. If royalties are charged for shut-in wells, they should be included here. One possible modification of this provision would be to charge the royalty on a per acre per year basis, if delay rentals are also charged on a per acre basis.

F. Reduction of Royalty (Optional)

After initial production has occurred for two years from the field in which the leased area is located, the State in its discretion, may reduce Lessee's obligations to pay royalty on all of the leased area or on any trace or portion of the leased area segregated for royalty purposes upon (1) request by the Lessee, (2) a clear showing by the Lessee that the revenue from all oil, gas, and associated substances produced from the field is insufficient to produce a reasonable rate of return with respect the Lessee's total investment in the field, and (3) a clear showing by the Lessee that a reduction in royalty will increase total production from the field.

[Comment]

During the life of a producing field, production is apt to decline to the point where the lessee's after-royalty revenues would not be sufficient to cover expenses. In such cases the royalty, if not lowered, would cause the lessee to abandon the field entirely at a net loss to both society and the lessor. Similarly, a marginal field may not be profitable to develop with a royalty of 1/6, but might be if the royalty were 1/10. This clause, found in the Alaska standard lease, empowers the state to lower the royalty in such cases. In practice, however, royalties are seldom reduced; although the U.S. Department of the Interior has had authority to lower royalties since 1953, it has never exercised this authority, at least through 1978.

Section 6: Share of Net Profit. Lessee shall pay to the State \_\_\_\_\_ percent (\_\_\_%) of the net profits from the operations under this lease. Net profits shall be determined as provided and paid in the manner prescribed in the net profits accounting procedure which is Exhibit \_\_\_\_ to this lease.

[Comment]

A net profits share provision may be either an alternative or supplement to a royalty provision. While most states charge only royalty payments, California relies on a net profits share alone, and Alaska requires both types of payment. Although the above provision (from California's standard lease) may appear to be simpler than a royalty provision, the appendix to the lease consists of 39 pages of accounting procedures for determining "net profits," listing in detail the expenses which may or may not be deducted from the revenues collected. Similarly, Alaska's calculation of net profits is based on a complicated statutory provision.

Section 7. Extension of Lease.

(a) If prior to discovery and production of oil or gas on said land or on acreage pooled therewith, Lessee should drill a dry hole or holes thereon,

or if after discovery and production of oil and gas the production thereof should cease from any cause, this lease shall not terminate if Lessee commences operations for drilling or reworking within ninety (90) days thereafter.

(b) If such dry hole(s) or cessation occurs within the primary term, the lease will not terminate if Lessee commences or resumes the payment or tender of rentals or commences operations for drilling or reworking on or before the rental paying date next ensuing after the expiration of ninety (90) days from the date of completion of the dry hole or cessation of production.

(c) If at the expiration of the primary term, or any extension thereof, or thereafter, oil or gas is not being produced on said land, or on acreage pooled therewith, but Lessee is then engaged in drilling or reworking operations thereon or shall have completed a dry hole thereon within ninety (90) days prior to the end of such term, the lease shall remain in force so long as operations on said well or on any other well are (re)commenced within ninety (90) days of the last cessation or dry hole completion and are prosecuted with no cessation of more than ninety (90) consecutive days. If such operations, drilling, or reworking result in the production of oil and/or gas, the lease shall remain in force so long thereafter as oil and/or gas is produced in paying quantities from said land or acreage pooled therewith, or as the provisions of this Section keep it in force.

[Comments]

This section includes three separate clauses which are usually included in oil and gas leases. The first, known as the "continuous operations clause," keeps the lease in effect after a well ceases to produce by allowing the lessee to return to operations within a given period of time. The "dry hole clause" similarly allows continuation of operations even after work stoppage resulting from drilling a dry hole. The third clause, the "well completion clause," expressly provides for the completion of well drilling at the end of the primary term. The amount of delay allowed is normally the same number of days for each of these provisions. Ninety days was used here because the existing North Carolina lease allows ninety days, but sixty days is more common.

Section 8: Duties of Lessee.

Lessee agrees to develop and manage the leased area with due diligence consistent with accepted operation and development practices and in accordance with the interests of both Lessor and Lessee, the provisions of this lease, and the laws, rules, regulations and executive orders of the United States and the State of North Carolina. Lessee agrees to conduct such development in a manner recognized as adequate and proper in order that Lessor may receive as early as possible the royalties provided for in this lease. Such conduct shall include, but not be limited to:

a. Diligent attempts to drill all exploratory holes to basement, or crystalline rock, in order to fully test the oil and gas potential of the entire sedimentary section at the well site;

b. After due notice in writing, diligent drilling and production of such other wells as the Department may reasonably require in order that the leased area or any part thereof may be properly and timely developed and produced in accordance with good operating practice;

c. At the election of Lessee, drilling and production of other wells in conformity with any system of well spacing or production allotments affecting the area, field or pool in which the leased area or any part thereof is situated, which is authorized or sanctioned by applicable law or regulation, or by the Department;

d. The use of all reasonable precautions by Lessee to prevent waste of oil and gas in the leased lands and to prevent the entrance of water through wells drilled to the oil or gas-bearing strata that may destroy or injure the oil or gas deposits.

[Comment]

This section is based on the existing North Carolina lease section on wells, but excludes the provision on offset wells, which has been included instead as a separate section (see Section 9: Offset Wells, below). A "due diligence" clause excerpted from Alabama's standard lease has been added. Also added is a waste and seepage provision from California; inclusion of this may, however, be redundant, since North Carolina oil and gas regulations already cover this topic.

Subsection b, as worded in North Carolina's current lease and reproduced here, might be interpreted to allow the lessor to dictate how the leased area will be explored. This is not done in most other jurisdictions. Before

incorporating this provision into the lease an alternative allowing the state to require drilling only for more specific purposes, such as prevention of waste, seepage, or drainage, should be considered.

Section 9: Offset Wells.

a. If, at any time during or after the primary term, oil, gas or any other liquid or gaseous hydrocarbon mineral should be produced in paying quantities in a well on land privately owned or on State land leased at a lesser royalty, which well is within any spacing or pooling unit distance established by the State Oil and Gas Board and draining the area included herein, the Lessee shall, within sixty (60) days after such initial production on such other land, begin in good faith and prosecute diligently the drilling of an offset well on the leased area, and such offset well shall be drilled to such depth as may be necessary to prevent undue drainage of the leased area. Lessee shall use all means necessary in a good faith effort to make such offset well produce oil, gas or other liquid or gaseous hydrocarbon minerals in paying quantities.

b. In addition to the specific offset drilling obligation above provided for wells within spacing or pooling unit distance, Lessee agrees to drill any and all wells necessary to protect the leased area from drainage of oil, gas or other liquid or gaseous hydrocarbon minerals by a well or wells on adjoining land privately owned or on State land leased at a lesser royalty, or to take any other steps reasonably necessary to protect the leased area against such drainage including, but not limited to obtaining the formation of appropriate drilling or production units.

c. In lieu of commencing operations for an offset well to State lands leased at a lesser royalty burden or to private lands, as above provided, Lessee may, at Lessee's option, commence compensatory payments equal to the royalties herein provided, computed on the value of one-half (1/2) of the oil, gas, or other liquid or gaseous hydrocarbons produced by the well in question, on and after the date operations would have otherwise have been commenced, value to be determined in accordance with the provisions of Section 5 [Royalties] of this lease. Such payments may be commenced within sixty (60) consecutive days after the date operations would otherwise have been commenced, but shall include any accrued compensatory payments. Thereafter, payments shall be due monthly in accordance with Section 5. Lessee shall not be in default in either commencing compensatory payments or in making further payments as above provided if despite good faith and due diligence Lessee is unable timely to obtain the production information on which such payments are to be based. In any such case, however, Lessee must on or before the due date of the payments, notify the Lessor in writing of Lessee's inability to make such payment, the reasons therefor, and Lessee's intent to make such payment at the earliest reasonable time. Compensatory payments may be continued, at Lessee's discretion, for not more than one year from the date on which offset operations would otherwise have been commenced. At the end of that time, or

within thirty (30) consecutive days from the end of any lesser period for which payments are made, Lessee shall comply with this offset obligation if the producing well continues to produce in paying quantities and the other conditions making this obligation operative are existent.

The compensatory payments required hereby are in addition to, and not in lieu of, any rental or other payment required by any other provision of this lease. The right to make compensatory payments is intended to permit Lessee to evaluate further the producing well, and the making of such payments shall not of itself be sufficient to maintain this lease in force and effect during the period allowed therefor if other payments required during this same period are not made; however, the making of any such compensatory payments shall not prejudice Lessee's right to rebut any of the above enumerated presumptions.

[Comment]

It is common in oil and gas leases to have provisions requiring offset wells under certain circumstances. The existing North Carolina lease form has a clause resembling an offset well clause but not such a clause per se. While subsections (a) and (b) here are typical of offset provisions, subsection (c) is more detailed than most such provisions for compensation as an alternative to offset drilling. Provisions of subsection (c) regarding nonpayment and the one-year limit on monetary compensation are optional and may be altered or eliminated. It might also be advisable to better define "draining" and "drainage" as used in subsections (a) and (b), either within those subsections or in a separate "Definitions" section. One such definition commonly used requires that the well on adjoining property "produce oil, gas, or other liquid or gaseous hydrocarbons in paying quantities for twenty (20) days (which need not be consecutive) during any period of thirty (30) consecutive days, or produces its monthly allowable during such thirty (30) consecutive day period."

Section 10: Directional Drilling. This lease may be maintained in effect by directional wells whose bottom hole location is on the leased area but that are drilled from locations on other lands not covered by this lease. In those circumstances, drilling shall be considered to have commenced on the leased area when actual drilling is commenced on those other lands for the

purpose of directionally drilling into the leased area. Production of oil or gas from the leased area through any directional well surfaced on those other lands, or drilling or reworking of that directional well, shall be considered production, drilling, or reworking operations on the leased area for all purposes of this lease. Nothing contained in this Section is intended to or shall be construed as granting to Lessee any interest, license, easement, or other right in or with respect to those lands in addition to any interest, license, easement, or other right that Lessee may have lawfully acquired from the State or from others.

[Comment]

This section is taken directly, with a few minor changes, from the Drilling section of the existing North Carolina lease. Such a directional drilling clause is standard in oil and gas leases.

Section 11: Repressuring; Use of Water.

Lessee shall have the use, free from royalty payments, of oil and gas produced from the leased premises for operations essential to the production of oil and gas hereunder and for repressuring the oil and gas bearing formations. For the latter purpose, such gas may be injected at any point in the same pool, as the term "pool" is defined by G.S. 113-389.

Lessee shall have the privilege to use, free of cost, such quantities of water from the leased premises as are reasonably necessary for all operations hereunder, except water from the wells of Lessor. All of the rights and privileges of this Section are specifically made subject to compliance with all applicable laws, rules and regulations of the State as may be in effect at the time of exercising these rights and privileges, even if such laws, rules and regulations prohibit actions allowed by the terms of this Section.

[Comment]

The language of this section is taken entirely, with some minor editorial changes, from the existing North Carolina lease. The repressuring provision, though not commonly expressed in other states, is usually implied by royalty clauses exempting from royalties that oil and gas necessary for production operations; to that extent, this clause may be redundant of the royalty provisions. Repressuring may, however, deserve separate mention since it is often essential to encourage the most efficient production of oil and gas. Water use provisions are common, though they may vary with the particular circumstances of the lease.

Section 12: Lessor's Right to Regulate Well-Spacing and Drilling:

Lessor shall have the right to determine the spacing of wells and the rates of production and drilling of wells to prevent the waste of oil and gas and promote the maximum economic recovery of oil or gas from, and the conservation of reservoir energy in, each zone or separate underground source or supply of oil or gas covered in whole or in part by this lease. Lessee agrees to comply with all laws, rules and regulations generally applicable to the spacing of wells and the rates of production and drilling of wells, as well as with any specific restrictions Lessor may impose on the premises or reservoirs included in this lease.

[Comment]

The first part of this provision was taken from California's standard lease. The second part is the converse of the State's right, requiring compliance by the lessee.

Section 13: Shut-in Wells.

(a) If at the expiration of the primary term, or at any time after its expiration, a well capable of producing gas or oil in commercial quantities is closed so that production ceases (shut-in), Lessee shall immediately notify the Department of the date that such well was shut-in. For the purpose of this lease, said well shall be considered a producing well, and shall be treated in the manner set forth in Section 5E above [Minimum Royalty].

[Comment]

Although the existing North Carolina lease does not restrict its shut-in clause to the period after the primary term, the majority of other states do. (Louisiana is one exception.) Eliminating such a restriction in this provision is one option. Other states also provide for shut-in royalties at twice the rate of delay rentals; however, this provision occurs only in those states where the minimum royalty is also double the delay rental. Louisiana has established a per acre rate for shut-in payments. Some states also limit their shut-in provisions to gas-producing wells.

(b) If production commences on a shut-in well during any given year, or if for some other reason the well ceases to be a shut-in well during any

given year, Lessee shall pay to Lessor a pro-rated amount of the royalty for that year on the acreage held. At no time, however, shall the total payment for any year be less than that provided for in Section 5E above [Minimum Royalty].

(c) If, at any time while this lease is being maintained in force and effect under the provisions of this section, gas or oil should be produced and sold or used in paying quantities from a well or wells completed in the same producing reservoir on adjacent state-owned lands leased at a lesser royalty or on adjacent private lands, which are draining the leased premises, the right to extend this lease by the shut-in royalty payments above shall cease at the expiration of the last 12-month period for which payment has been made. Thereafter, Lessee may maintain this lease in force and effect only by opening said well as an offset well or by paying compensatory royalty to Lessor, as provided for in Section 7, above [Offset Wells].

[Comment]

This important provision for compensatory royalties in the case of shut-in wells is absent from the existing North Carolina lease. Although compensatory royalties are discussed above under the provision for offset wells, it is vital that they be applied to shut-in wells as well.

(d) Lessee hereby agrees that it shall attempt to market such gas or oil mentioned in subsection (b) above in a manner that would be most beneficial to Lessor. Nothing herein shall relieve Lessee of the obligation of reasonable development of the leased premises, nor of the obligation to drill offset wells as required by Section 7, above [Offset Wells].

[Comment]

This is an expanded version of a provision which is in the current North Carolina lease. A reference to the duties of development and of drilling offset wells is included to reinforce their importance.

#### Section 14: Pooling and Unitization.

##### Option 1:

Lessee's right to pool or unitize the leasehold estate and mineral estate covered by this lease with other land, lease or leases into one or more operating units for the production of oil and gas, or separately for the production of either shall be governed by rules and regulations promulgated by the Secretary of the Department of Natural Resources and Community Development as are in effect at the time of the proposed pooling or unitization.

[Comment]

It is common practice to include a unitization clause in the lease, as North Carolina has done in the past. This clause is taken almost verbatim from the existing lease. While pooling and unitization both refer to the combination of leases and land for more effective and efficient production, pooling specifically means the combination of enough land to form a single well-drilling unit, and unitization refers to a larger field-wide or partial field-wide operation.

Option 2:

Lessee, at its option, is hereby given the right and power to pool or combine the acreage covered by this lease or any portion thereof with other land, lease or leases in the immediate vicinity thereof, when in Lessee's judgment it is necessary or advisable to do so in order properly to develop and operate said premises in compliance with the spacing rules of the Department or other lawful authority, or when to do so would in the judgment of Lessee promote the conservation of the oil and gas in and under and that may be produced from said premises. Lessee shall execute in writing an instrument identifying and describing the pooled acreage. The entire acreage so pooled into a tract or unit shall be treated, for all purposes except the payments of royalties on production from the pooled unit, as if it were included in this lease. If production is found on the pooled acreage, it shall be treated as if production is had from this lease, whether the well or wells be located on the premises covered by this lease or not. Under this lease, Lessor shall receive on production from a unit so pooled only such portion of the royalty stipulated herein as the amount of acreage placed in the unit or his royalty interest therein on an acreage basis bears to the total acreage so pooled in the particular unit involved.

[Comment on Option 2]

This option, an example of a basic pooling clause, is more inclusive than Option 1. If a more detailed clause such as this one is desired, it should be revised to summarize the regulations in effect at the time of leasing and any additional requirements deemed necessary. Considering the vagueness of North Carolina's pooling regulations (15 NCAC 5D .0006), the lease provision should be as comprehensive as possible. If, however, the regulations are made more comprehensive, Option 1 would be preferable to avoid conflicts between the

lease and the regulations. In any case, the regulations and the lease should together cover: 1) basis and authority of the lessee to pool or combine acreage; 2) the method of designation of the pooled acreage; 3) the effect of production within the unit upon acreage within and outside the unit; and 4) the apportionment of royalties among parties to the pooling or unitization agreement.

Option 3:

(a) Lessee may unite with others, jointly or separately, in collectively adopting and operating under a cooperative or unit agreement for the exploration, development, or operation of the pool, field, or like area or part of the pool, field, or like area that includes or underlies the leased area or any part of the leased area whenever the State determines and certifies that the cooperative or unit agreement is in the public interest.

(b) Lessee agrees, within six months after demand by the State, to subscribe to a reasonable cooperative or unit agreement that shall adequately protect all parties in interest, including the State. The State reserves the right to prescribe such an agreement.

(c) With the consent of Lessee, and if the leased area is committed to a unit agreement approved by the State, the State may establish, alter, change, or revoke drilling, producing, and royalty requirements of this lease as the State determines necessary or proper to secure the proper protection of the public interest.

(d) Except as otherwise provided in this subparagraph, where only a portion of the leased area is committed to a unit agreement approved or prescribed by the State, that commitment constitutes a severance of this lease as to the unitized and nonunitized portions of the leased area. The portion of the leased area not committed to the unit will be treated as a separate and distinct lease having the same effective date and term as this lease and may be maintained only in accordance with the terms and conditions of this lease, statutes, and regulations. Any portion of the leased area not committed to the unit agreement will not be affected by the unitization or pooling of any other portion of the leased area by operations in the unit, or by suspension approved or ordered for the unit. If the leased area has a well certified as capable of production in paying quantities on it before commitment to a unit agreement, this lease will not be severed. If any portion of this lease included in a participating area formed under a unit agreement, the entire leased area will remain committed to the unit upon contraction of the unit and this lease will not be severed.

[Comment on Option 3]

This clause, from Alaska, gives both the lessee and the State the power to pool or unitize leased areas, and contains provisions that, if not included in the regulations, would be important to include. A particularly important provision is subparagraph (d), a severance clause which designates the pooled area as a separate tract for lease purposes, since different terms might be advisable for the newly pooled area.

Section 15: Severance of Minerals.

It is understood and agreed by the parties hereto that the title to any and all minerals covered by this agreement shall be and remain in the State of North Carolina until such minerals are severed from the lands covered by this agreement.

[Comment]

This provision is included in the existing North Carolina lease and may clarify some misconceptions as to the relationship created by the lease. The majority of other states, however, do not have a similar provision.

Section 16: Inspection.

Lessee agrees to keep open at all reasonable times for the inspection by any duly authorized representative of Lessor: the leased area; all wells, improvements, machinery and fixtures thereon; and all books, accounts, and records relating to operations, surveys, or investigations on or with regard to the leased area, or under the lease.

[Comment]

This provision, taken from the most recent North Carolina lease, is a standard part of any state oil and gas lease. It can be included as a separate provision or can be subsumed as a subsection of the recordkeeping and reporting requirements (See Section 17).

Section 17: Records and Reports.

(a) Lessee shall provide the Department accurate reports of expenses and expenditures incurred pursuant to drilling test wells under this lease or in performing other geological and geophysical work under this lease. Said report shall be provided by Lessee within thirty (30) days after the completion of any work performed hereunder. The Department shall have the right at any time to require in writing that Lessee submit a written report of expenses and expenditures within thirty (30) days after receipt of said request.

(b) In addition, Lessee shall furnish to the Department copies of all geological, geophysical, or geochemical data, results, and interpretations within ninety (90) days after the completion of said work, or within ninety (90) days after the termination of the lease, whichever comes first. To the extent these data, results, and interpretations are deemed proprietary or confidential in nature by Lessee, Lessee may request Lessor to treat the information as confidential for a period not to exceed five (5) years. To the extent it may legally do so, Lessor will grant the request if satisfied that the information is proprietary and confidential in nature. Upon an agreement as to confidentiality, Lessor shall have the right to use the information, but will not allow its inspection, examination, or copying as a public record unless required to do so by a court of competent jurisdiction.

(c) No part of this section is intended in any way to change or abrogate the requirements of the laws, rules, and regulations of the State of North Carolina. If any inconsistency should exist between this Section and said laws, rules, and regulations, the latter shall govern.

(d) Lessee shall assume no responsibility or liability for the interpretations furnished to Lessor pursuant to the terms of this Section.

[Comment]

A record-keeping provision is a well-established part of all oil and gas leases. Some alternatives to the continuous submission of reports and records to the Department would be to require that such records and reports be submitted at periodic intervals (e.g., monthly, bi-monthly, quarterly), that such records and reports be kept by the lessee to be submitted to the Department only upon request of the Department, or that they be kept available for State inspection.

Other states have provided in the lease a more specific list of the records and reports required; if the State is interested in any specific data it would be wise to list it in an "including but not limited to . . ." phrase.

One possibility would be to require that some important documents be submitted on a regular basis and that others be retained by the lessee for inspection or submittal upon request by the Department.

The five-year period for confidentiality was chosen because it is the period used in the existing North Carolina lease. This period varies among states, ranging from three years to ten years.

Subsection (d) was included here because it is part of the existing North Carolina lease. A similar provision does not appear in the leases of other states and its purpose and necessity are doubtful.

Other requirements may be made under this section. Florida's lease, for instance, requires the lessee to furnish annual reports both estimating "the quantity of proved reserves of oil and gas underlying the lands covered by this lease," and giving the status of operations on the land.

Section 18: Abandoned Wells.

In the event any well is drilled on the leased premises and, after being drilled, is found to be dry or should later become dry, or the use thereof be discontinued for one year for any reason, Lessee shall permanently close and seal such well to prevent seepage or leakage therein of any water or brine, in compliance with the regulations established by the Department. Provided, however, it is understood by both parties that the provisions of this section shall not apply to shut-in wells.

[Comment]

This section, taken from the existing North Carolina lease, complements both the dry hole clause in Section 6 and the oil and gas regulations promulgated by the Department. However, this provision contradicts the existing regulation requiring that a well be plugged after thirty days of non-operation (15 NCAC 5D .0009). The time period in the lease should be changed to correspond with the regulation, or this section should be abandoned in favor of the regulations.

Section 19: Removal of Property.

(a) Upon the termination or surrender of this lease in whole or in part, as provided in this lease, Lessee shall within a period of one (1) year thereafter remove from the premises no longer subject to the lease all structures, machinery, equipment, tools, and materials which can safely be removed. Such removal shall be in accordance with applicable regulations and orders of the Department and shall concur with regulations regarding casing, plugging, and shut down of wells. However, Lessee may continue with the approval of the Department to maintain any such property on the leased area for whatever longer period it may be needed, as determined by the Department, for producing wells or for drilling or producing on other leases. Upon expiration of the period provided for herein, at the option of the State, any machinery, equipment, tools, and materials that Lessee has not removed from the leased area or portion of the leased area becomes the property of the State or may be removed by the State at Lessee's expense.

[Comment]

This is a slightly modified version of North Carolina's existing provision. Other states provide for a shorter time period (e.g., 120 days) or designate that equipment be removed within a "reasonable time." In North Carolina, where it is unlikely that another lessee will want to do work in the same area immediately, the one year period should be both reasonable and adequate, and is therefore better than either a shorter period (with possible extension) or an ambiguous "reasonable time." The final sentence of this subsection, not currently included in North Carolina's lease, is a clause used in some other states and should be considered here.

(b) Upon the termination of this lease for any cause, Lessee shall not, in any event, be permitted to remove the casing or any part of the equipment from any producing, dry, or abandoned well or wells without the written consent of the Department and concurrence with applicable regulations regarding casing, plugging, and shut-down of wells; nor shall Lessee, without the written consent of the Department remove from the leased premises the casing or any other equipment, material, machinery, appliances or property owned by Lessee and used by Lessee in the development and production of oil or gas therefrom until all dry or abandoned wells have been plugged and until all slush or refuse pits have been properly filled and all broken or discarded lumber, machinery, or debris shall have been removed from the premises to the Department's satisfaction.

[Comment]

This subsection, based on the Texas lease, makes the removal of equipment dependent on Departmental approval, reaffirming the administrative regulations requiring the same. The Department's approval is desirable to assure that the wells are completely shut down before equipment is removed. Together, subsections (a) and (b) put the lessee under an affirmative duty to remove its equipment but require state approval before the duty is undertaken, so that clearance of the leased area can occur and the buildup of debris can be prevented in accordance with prescribed rules and regulations.

Section 20: Compliance With Laws and Regulations; Interference With Others.

(a) All expressed or implied covenants of this lease shall be subject to all applicable Federal and State laws, executive and administrative orders, rules and regulations in effect on the effective day of this lease and, insofar as is constitutionally permissible, after the effective date of this lease. Lessee shall specifically comply with all regulations issued by the Department relating to exploration, development, and production, including but not limited to those regarding bonding, exploration plans, drilling, casing and plugging of wells, and the prevention of waste. Nothing herein shall be deemed to restrict the power of the State or of its agencies or subdivisions to enforce all provisions of law and all applicable regulations; the procedures applicable to the enforcement of any law, rule, or regulation shall be in the manner set forth therein.

(b) This lease is made subject to the superior rights of navigation of the waters herein described. No structure shall be built, nor any dredging and filling operations shall be undertaken therein until such structure or operations have been authorized by the governments of North Carolina and the United States and the proper officials thereof where such authorization is required by law, order, or governmental regulations.

(c) This lease is also made subject to all leases, easements, permits, or licenses presently in existence to which Lessor is a party. This lease shall be subject to any oyster or clam bed lease heretofore granted by the Secretary of the Department of Natural Resources and Community Development (formerly the State Board of Conservation and Development) or any other authorized agency.

(d) Lessee hereby agrees, as one of the obligations of this lease, that in exercising its rights and duties under this lease it will take all prudent or required precautions to prevent pollution of the land, air, or waters, of the State of North Carolina. Lessee will comply with and be subject to all applicable laws and regulations validly adopted or issued by the State of

North Carolina, or its agencies, or by the United States, or its agencies. Lessee agrees to procure all necessary permits, licenses, or certifications before undertaking any activity which may be harmful to the environment and may require such permit, license, or certification. It is specifically provided that the Department shall have the right and authority to inspect any part of Lessee's operations at any reasonable time to determine whether any pollution of the State's surface or ground waters is resulting from such operation.

(e) The prospecting, exploration, mining, and concentrating operations of Lessee within the exploration area shall be performed in a good and workmanlike manner in accordance with established practices and in a manner that will not interfere with navigation along the channels of the waterways within the prospecting area or unreasonably interfere with navigation elsewhere, including wharves and docks. No such operations shall be carried out in such a manner as to destroy or imperil any highway, railway, or bridge within the lease area or to interfere with property or equipment used by commercial fishermen within the lease area.

[Comment]

Several sections of the existing North Carolina lease were re-ordered and consolidated to create this section. Subsection (c) is unique to North Carolina's lease and might cause conflicts with owners of surface leases on the lease's covered acreage by implying that surface leases have superior rights. Depending on state policy in regard to this type of conflict, the state should consider deleting this subsection (see Chapter 5). Subsection (d) on pollution abatement may be highlighted in a section of its own if so desired. Likewise, subsection (e), a separate section in the existing lease, may be so separated. There is no analogous provision to subsection (e) in the leases of other states, but it is probably valuable to include it here.

Section 20: Rights of Municipalities and Other Parties.

This agreement is made subject to any and all rights and interests of any municipality which may be located within the boundaries or have jurisdiction over the lease area herein described and is further made subject to all rights, title and interest of individuals which may be of record.

Section 21: Force Majeure; Suspension.

Option 1:

(a) If, prior to discovering oil, gas, or other minerals covered hereby, Lessee is prevented from complying with any express or implied covenant of this lease, from conducting drilling operations thereon, or from attempting to produce oil or gas therefrom, after good faith effort, by reason of war, rebellion, riots, strikes, vandalism, acts of God, or any valid order, rule or regulation of government authority, including regulations for obtaining required federal or state environmental or other permits, then while so prevented, Lessee's obligation to comply with such covenant shall be suspended and this lease, and the time for complying with any provision hereof, shall be extended while and so long as Lessee is prevented, by any such cause, from drilling, reworking operations, or attempting to produce oil or gas from the leased premises; provided, however, that nothing herein shall be construed to suspend the payment of delay rentals in order to maintain this lease in effect during the primary or extended term in the absence of such drilling or reworking operations or production of oil or gas; and further provided, that in the event Lessee invokes the provisions of this paragraph to excuse performance by reason of failure or inability to obtain required Federal or State permits or authorizations Lessee shall produce and submit to Lessor all data, documents or other information required by Lessor to establish the good faith attempts of Lessee to obtain said permits or authorizations.

(b) If oil, gas or any other mineral covered hereby is discovered but production is prevented by any of the causes in Subsection (a) above, this lease shall be considered producing and shall continue in full force and effect until Lessee is permitted to produce said minerals, and as long thereafter as same actually is produced in paying quantities; provided, however that Lessee, as an express condition for the extension of the lease without production, shall pay to Lessor: (i) for an oil or other liquid hydrocarbon well, the sum of \_\_\_\_\_ Dollars (\$ \_\_\_\_\_) per annum for each acre of the leased area; or (ii) for a gas well, the shut-in gas royalty specified above, payment on both cases to be made within ninety (90) consecutive days from the date that production is prevented and annually upon such payment date until production is resumed.

[Comment]

This clause is taken from Mississippi's standard oil and gas lease and has the effect of suspending the obligations of the lease for any delay caused by the listed reasons. Under this option, payment is required to keep the lease in effect during both the primary term and thereafter, with different formulas used for payment depending on during which phase of exploration and development the delay may occur. While this double standard may cause confusion, it should be consistent with the rest of the lease.

Option 2:

Should Lessee be prevented from complying with any express or implied covenant of this lease, from conducting drilling operations thereon, or from producing oil and/or gas therefrom, after effort made in good faith, by reason of war, rebellion, riots, strikes, acts of God or any order, rule or regulation of governmental authority, then while so prevented, Lessee's obligation to comply with such covenant shall be suspended upon proper and satisfactory proof presented to Lessor in support of Lessee's contention, and Lessee shall not be liable for damages for failure to comply therewith; this lease shall be extended while and so long as Lessee is prevented, by any such cause, from drilling, reworking operations or producing oil and/or gas from the leased premises; provided, however, that nothing herein shall be construed to suspend the payment of rentals during the primary or extended term, nor to abridge Lessee's right to a suspension under the terms of this lease.

[Comment]

This option, more concisely stated than Option 1, comes from Texas. Although it also provides for rental payments during a delay, it relies on other provisions in the lease to delineate these payments. It emphasizes, instead, suspension of lessee's duties to perform under the lease. It is wise to include a provision requiring some proof of the cause for delay, as this option does; however this option's failure to specifically include government delay in the processing of permits as a justified cause for delay may create problems.

Option 3:

The obligations imposed upon Lessee by this lease may be suspended whenever Lessee is prevented from complying with them by wars, strikes, riots, acute and unusual labor or material shortages, acts of God, laws, rules and regulations of any federal, state, county or municipal agency or by other unusual conditions that are beyond the control of Lessee. In order for any obligation imposed upon Lessee to be suspended, Lessee must notify the State in writing as soon as possible that a condition warranting suspension has arisen. The notification shall state the nature of the condition, an estimate of the condition's duration and the steps to be taken by Lessee to eliminate the condition. Lessee shall use its best efforts to eliminate the condition and notify the State in writing as soon as the condition no longer exists.

[Comment]

This option, taken from California's lease, varies from the others in that it has an open ended "other unusual conditions" provision; while it may be useful to include these unlisted, but nevertheless justifiable causes for delay, it might also be a source of potential conflict when a difference of opinion arises as to whether a cause is justifiable. This clause also has the effect of suspending all obligations of the lessee, delay rental payment included. One value of this clause is the diligence required on lessee's part in trying to eliminate the condition causing delay.

Option 4:

Should Lessee be prevented from complying with any express or implied covenant of this lease, from conducting drilling operations or producing any products as herein defined from the leased premises, after effort made in good faith, by reason of war, rebellion, riots, strikes, acts of God including but not limited to fire, storms, floods, washouts, landslides and lightning, or any laws, acts, orders, rules, regulations or demands of governmental authority (including regulations for obtaining required State or Federal environmental or other permits), then while so prevented, Lessee's obligation to comply with such covenant shall be suspended upon proper, satisfactory and convincing proof presented to Lessor in support of Lessee's contention; and Lessee shall not be liable for damages for failure to comply therewith. This lease shall be extended while and so long as Lessee is prevented, by any such cause, from drilling, reworking operations or producing oil and/or gas from the leased premises, provided, however, that nothing herein shall be construed to suspend the payment of rentals during the primary or extended term, nor to abridge Lessee's right to a suspension under any provision herein or under any applicable statute of this state. Lessee shall be required at all times to use reasonable diligence to overcome such causes as described above as promptly as circumstances will permit, and to recommence operations hereunder as soon as is reasonably possible.

[Comment]

There is a partial force majeure clause in the existing North Carolina lease; this option expands upon that one to provide more complete coverage. Provisions have been added here to provide for delay due to acts of God and to specify that delay due to procurement of permits is included as a government action. It has become common to include a force majeure clause in oil and gas

leases, out of fairness to the lessee acting in good faith. While the burden is still on the lessee to prove a force majeure to the lessor, the lessee is given some relief from its obligations if such cause for delay can be proven. The clause included here is a combination of the clauses of several states, which vary as to their specificity in listing acts of God and specific inclusion of delay due to procuring permits. Since possible conflicts within the lease between the force majeure clause and other clauses dealing with delays might arise, it might be wise to include in those other clauses mention of force majeure.

Section 23. Severability.

Option 1:

If it is finally determined in any judicial proceeding or by agreement of the parties hereto that any provision of this lease is illegal or unconstitutional, Lessor and Lessee may jointly determine and agree by a written amendment to this lease that, in any consideration of the promises, terms, conditions, and covenants contained in that written amendment, the invalid portion will be treated as severed from this lease and that the remainder of this lease, as amended, will remain in effect.

Option 2:

In the event that any provision of this lease is finally determined to be illegal or unconstitutional in any judicial proceeding or by agreement of the parties hereto, its nullity shall in no way impair the validity of any other portion of the lease not declared invalid; provided, that Lessee shall not directly or indirectly institute or cause to be instituted any action seeking to declare the nullity or the unenforceability of this lease as a whole.

[Comment]

This existing North Carolina lease has no severability provision; the effect of this may be that the entire lease will be voided if any provision is declared illegal. If this possibility is to be avoided, one of the above severability clauses should be included in the lease. If at the time of signing the original lease it can be agreed that the provisions of the lease

will be severable, the second option should be chosen; otherwise, the first option, making severability optional, should be selected.

Section 24. Indemnification.

Option 1:

Lessee agrees to indemnify and save Lessor harmless against and from any and all claims of any nature whatever, including without limitation claims for loss or damage to property or injury to persons, caused by, or resulting from, any operation on the leased area conducted by or on behalf of Lessee; provided that Lessee shall not be held responsible to Lessor under this subsection for any loss, damage, or injury caused by, or resulting from:

- (a) any negligent action of Lessor other than the exercise or performance of (or the failure to exercise or perform) a discretionary function or duty on the part of a State agency or an employee of such an agency, whether or not the discretion involved is abused; or
- (b) Lessee's compliance with an order or directive of Lessor against which an appeal by Lessee under applicable rules and regulations is filed before the cause of action for such a claim arises and is pursued diligently thereafter.

[Comment]

This detailed clause, taken from the existing North Carolina lease, is probably the fairest possible provision to the lessee, making the lessee liable only for what it may expect to be liable for. Other states, however, employ a blanket indemnification clause, such as Option 2.

Option 2:

Lessee shall indemnify the State of North Carolina, its officers, agents and employees against all claims, demands, causes of action or liabilities of any kind which may be asserted against or imposed upon the State of North Carolina, its officers, agents or employees, by any third person or entity arising out of or connected with the issuance of this lease, operations hereunder, or the use by Lessee, its agents, employees or contractors of the leased lands.

[Comment]

This is a more common form of indemnification clause, placing all liability on the lessee.

Some additional provisions, taken from the California standard oil and gas lease, might be considered as optional amendments to the indemnification clause. These regard liability for damage to the lessor's property from the lessee, and liability insurance for the lessee. If these options are included, the Section should be renamed Liability; the provisions might be drafted as follows:

Lessee shall be liable to the State for all damage to any reservoir underlying the leased lands and any loss of oil, gas or other hydrocarbon substances to the extent that they are caused by the negligence of, or the breach of any provision of this lease by, or noncompliance with any applicable statutes or regulations by Lessee, its employees, servants, agents or contractors. Nothing in this lease shall diminish any other rights or remedies which the State may have in connection with any such negligence or breach.

Lessee shall furnish upon execution of this lease a certificate showing that at all times throughout the life of this lease, Lessee is insured against damages to third persons and their property resulting from an oil spill or other pollution caused by operations under this lease. The insurance shall be for an amount not less than \_\_\_\_\_ dollars (\$ \_\_\_\_\_) for each occurrence. The minimum amount may be raised by the State if economic conditions change. The certificate of insurance coverage shall include the State of North Carolina as a named insured, or shall demonstrate to the satisfaction of the State that Lessee is capable of self-insuring the risk. The certificate of insurance shall remain in effect at all times throughout the life of the lease. A new certificate of insurance meeting the above requirements may be substituted by the Lessee with the State's approval.

Section 25. Assignment of Lease; Successors in Interest.

(a) This lease shall not be assigned in whole or in part without the written consent thereto of Lessor, who shall not unreasonably withhold such consent. Provided, however, that if Lessee shall request, by registered mail addressed to both the Secretary of the Department of Administration and the Secretary of the Department of Natural Resources and Community Development, approval of an assignment of the whole or any part of the acreage covered hereby, and Lessor does not object within ninety (90) days after receipt of such request, then such request shall be deemed approved by Lessor. Any request for consent to or approval of assignment shall contain the full name and address of the Assignee, a description of the lease portion(s) to be assigned, and any other information as may reasonably be requested by Lessor. With the approval of Lessor, either affirmatively or by non-action, this lease may be assigned in whole or in part.

(b) The provisions of this agreement shall be binding upon and inure to the benefit of the heirs, devisees, successors and assigns of the parties hereto.

[Comment]

Some sort of assignment provision is basic to any lease. This clause is modeled on the existing North Carolina clause, with a few additions. The first is that the lessor will not unreasonably withhold consent; this addition is necessary to prevent arbitrary or unfair action on the part of the lessor. The second addition is that the lessor be notified who the assignee is; this is merely common sense. Also, the lessor's decision on whether to consent to the assignment may depend on whether the lessor can expect the assignee to comply with the provisions of the lease. Finally, the clause making the lease binding on successors or assignees is included here; alternatively, this may be included as a separate section as is currently the case.

Since assignments are often made in return for a royalty interest (see, for instance, the history of North Carolina lease transactions in Figure 2-3), it is conceivable that, like the lessor's royalty interest, these overriding royalties could cause the assignee to choose not to develop a marginal property or to abandon it early (see Section 6F, above). Since it is in the assignor's interest to voluntarily reduce the royalty in such circumstances, the problem could be left to negotiation between the assignor(s) and the assignee. Alternatively, the state could include a lease provision here or in the Reduction of Royalty section stating that any reduction in royalty by the state for purposes of extending the economic life of the lease will apply proportionally to overriding royalties as well, and that clauses recognizing this authority must be included in any lease assignment.

Section 26. Surrender of Lease.

Lessee may at any time surrender this entire lease or any officially designated subdivision of the leased area by filing with the Department a written relinquishment, which shall be effective as of the date of filing. No surrender of the lease or of any portion of the leased area shall relieve Lessee or his surety of the obligation to make payment of all accrued rentals and royalties or to abandon all wells on the area to be surrendered in a manner satisfactory to the Department and in compliance with the applicable rules and regulations issued by the Department. After that, Lessee shall be released from all obligations under this lease with respect to the surrendered lands.

Section 27: Notice.

Any notices required or permitted under this lease shall be given by electronic media producing a permanent record or in writing and shall be delivered personally or by registered mail. Unless otherwise specified in this lease, notices from Lessee to Lessor shall be delivered to both the Secretary of the Department of Natural Resources and Community Development and to the Secretary of the Department of Administration of the State of North Carolina, at \_\_\_\_\_ [address] \_\_\_\_\_, and notices from Lessor to Lessee shall be delivered to Lessee's executive offices at \_\_\_\_\_ [address] \_\_\_\_\_ until otherwise designated by either party to the other. If any party to this lease changes its address from the one shown herein, that party shall notify the other of such change within thirty (30) days of such move by the means described above. Any notice given under this section shall be effective when delivered to the designated parties.

Section 28. Default; Cancellation.

It is understood and agreed by the parties hereto that if there is any default or violation on the part of Lessee of any stipulation, agreement, covenant, or term of this agreement, or if Lessee fails to comply with any of the provisions of this lease, all work so violating this lease shall cease immediately whether the violation occurs during the primary term or under any extension then in effect, and Lessee shall institute such measures as necessary to abate such default or violation; then, if Lessee fails to correct said defaults or violations within thirty (30) days after notice from Lessor of the violation or default, it shall be lawful for Lessor to cancel this agreement and re-enter the premises hereby leased, to repossess and take possession of the same, and to use, enjoy or re-lease the same as if this lease had not been entered into. In the event correction by Lessee requires changes to the plant, equipment, or operations of Lessee, Lessee shall have a reasonable time necessary to make such changes after notice of violation or default before Lessor can exercise its right to cancel. Failure by Lessor to enforce this right or any other granted under this lease in any particular instance shall not constitute a waiver by Lessor of that or any other provision.

Provided, however, in the event Lessee, upon receiving notice of violations or default from Lessor, notifies Lessor within fifteen (15) days after receipt of such notice that it desires to arbitrate the issue of violation or default, arbitration shall proceed in the manner described in Section 31 below. It shall be lawful for Lessor to cancel this agreement if Lessee fails to correct said violations within thirty (30) days after the arbitration award or, in the event changes are ordered in the plant, equipment or operations of Lessee, within a reasonable time necessary to make such changes, which time shall be specified in the arbitration award.

It is specifically provided, however, that the provisions of this section shall not apply to any violation of the laws of North Carolina, or its subdivisions, or the United States, or to any rules or regulations adopted pursuant thereto, and that any violations thereof shall be governed by the provisions of or procedures set forth therein.

[Comment]

The existing North Carolina default clause has been modified slightly to produce this section. The clause dealing with failure to enforce the State's right to cancel was added, and the remainder was reworded. Most leases have a provision with a similar effect, but many are worded differently from this one, listing all the possibilities for default and not elaborating on procedures for cancellation or forfeiture. The provision above is more desirable, then, because it covers default in general and provides for a fair method of cancellation by the lessor.

It would also be useful to include a provision allowing the state to cancel the lease, with compensation, should it become evident that further development on the lease is not in the state's best interests. The following is a slightly modified version of a provision in the Alaska lease, which itself was adapted from Section 5 of the U.S. Outer Continental Shelf Lands Act:

The State may cancel this lease at any time if the State determines, after Lessee has been given notice and a reasonable opportunity to be heard, that (1) continued operations pursuant to this lease probably will cause serious harm or damage to biological resources, to property, to mineral resources, or to the marine, coastal, or human environment, (2) the threat of harm or damage will not disappear or decrease to an acceptable extent within a

reasonable period of time, and (3) the advantages of cancellation outweigh the advantages of continuing this lease in effect. Any cancellation under this subsection shall not occur unless and until operations under this lease have been under suspension or temporary prohibition by the State, with due extension of the term of this lease, continuously for a period of \_\_\_\_\_ years or for a lesser period upon request of Lessee. Any cancellation under this subparagraph will entitle Lessee to receive compensation as Lessee demonstrates to the State is equal to the lesser of (1) the value of the cancelled rights as of the date of cancellation, with due consideration being given to both anticipated revenues from this lease and anticipated costs, including costs of compliance with all applicable regulations and stipulations, liability for clean-up costs or damages, or both, in the case of an oil spill, and all other costs reasonably anticipated under this lease, or (2) the excess, if any, over Lessee's revenues from this lease (plus interest on the excess from the date of receipt to date of reimbursement) of all consideration paid for this lease and all direct expenditures made by Lessee after the effective date of this lease and in connection with exploration or development, or both pursuant to this lease, plus interest on that consideration and those expenditures from the date of payment to the date of reimbursement. Cancellation under this (sub)section may also be submitted into arbitration as provided for below.

[Comment]

The problem of permits issued or overseen by independent commissions was discussed in Chapter 5. To allow the state to cancel the lease, with compensation, should a permit from one of these commissions be denied, the above provision could be used or an additional, more explicit provision could be included, along the following lines:

The State, at the request of the Lessee, may cancel this lease if (1) a permit necessary to develop this lease has been denied or has been granted under conditions that are economically or practically impossible to comply with, (2) Lessee was not substantially forewarned of such impediments to develop in the formal notice of sale, and (3) Lessee has exhausted all other avenues for resolution of the impasse. If the State denies the Lessee's request for cancellation with compensation under this provision, Lessee may submit its claim to arbitration as provided for below. During the period between submission of Lessee's request and its final settlement, all operations under the Lease shall be suspended, with due extension of the lease term. If the lease is cancelled by the state under this provision, Lessee shall be entitled to compensation in accordance with Section \_\_\_, above.

Section 29: Sales Contracts and Exchange Agreements.

Lessee shall submit to the State for approval all contracts and other agreements for the sale, exchange, or other disposition of oil, gas, natural gasoline, and other substances produced from the leased lands. Lessee shall not sell or otherwise dispose of the lease production except in accordance with sales contracts or other methods first approved in writing by the State.

[Comment]

This section, taken from California's lease, is optional and does not appear frequently in oil and gas leases. If the State feels the need to have some control over who the lessee is doing business with and how, either this sort of provision or one establishing minimum standards for the lessee's contracts would be useful.

Section 30: Conflicts and Ambiguities.

No express obligation imposed upon Lessee shall relieve it of its existing duty to exercise due diligence in exploration, development, operation, marketing or protection activities except to the extent of direct conflict with such express obligation, and all such express obligations shall be construed as providing minimal standards only. In case of ambiguity, this lease always shall be construed in favor of Lessor and against Lessee. Notwithstanding any of the provisions, covenants or stipulations contained in this lease, should there be any conflict in any of the provisions of this lease with the law governing the issuance and operation of leases on the area herein described, the provisions of such law shall be deemed written into this lease and shall control.

Section 31: Arbitration.

In the event any dispute is required to be submitted for arbitration by the terms of Section 28 of this agreement, arbitration shall proceed in the following manner:

- (a) Each party shall select an arbitrator within five (5) days after Lessee gives notice of its desire to arbitrate.
- (b) The arbitrators selected by the parties shall select a third arbitrator as chairman of the arbitration panel within ten (10) days after this arbitration provision comes into effect.
- (c) The arbitration board shall meet and decide the dispute submitted to it within fifteen (15) days after the appointment of the independent arbitrator.

- (d) The decision of the board of arbitrators shall be binding on the parties provided such decision is not contrary to existing State or Federal laws, rules and regulations.
- (e) The costs of the arbitrators appointed by the parties shall be borne by the party making the appointment. The expense of the independent arbitrator and any other expenses incident to the arbitration proceedings shall be borne equally by the parties.

Section 32: First Lien.

The State of North Carolina shall have a first lien upon all production from the leased area to secure payment of all unpaid royalty and other sums of money that may become due under this lease.

Section 33: No Warranty of Titles.

It is specifically understood that Lessor does not warrant that it holds absolute fee simple title to any of the land described in this lease and that nothing in this lease may be construed to compel Lessor to establish good title or defend its title to all or any part of the leased premises. It is understood that Lessee shall have no recourse whatsoever against Lessor for failure of Lessor's title, it being expressly agreed that Lessor shall not be required to return any payments received hereunder or be otherwise responsible to Lessee therefore.

Section 34: Definitions.

All words and phrases used in this lease are to be interpreted as they are ordinarily used, except where applicable laws, regulations, or orders define them otherwise, or their ordinary definition differs from the one listed below. The following words have the following meanings unless the context unavoidably requires otherwise:

- (1) "Oil" means crude petroleum oil and other hydrocarbons, regardless of gravity, that are produced in liquid form by ordinary production methods, including liquid hydrocarbons known as distillate or condensate recovered by separation from gas other than at a gas processing plant.
- (2) "Gas" means all natural gas (except helium gas) and all other hydrocarbons produced that are not defined in this lease as oil.
- (3) "Drilling Operations" means the act of boring a hole to reach a proposed bottom hole location through which oil or gas may be produced if encountered in paying quantities, and includes redrilling, sidetracking, deepening, or other means necessary to reach the proposed bottom hole location, testing, logging, plugging, and other operations necessary and incidental to the actual boring of a hole and drawing a product from it.

- (4) "Paying quantities" means quantities sufficient to yield a return in excess of operating costs, even though drilling and equipment costs may never be repaid and the undertaking considered as a whole may ultimately result in a loss.

[Comment]

The value of a Definitions Section is to locate in one place all the definitions which may cause confusion. It also serves to prevent the cluttering of the lease provisions themselves with the technical meanings of the terms used. Care should be taken in wording these definitions so that the words have their exact intended meanings and are consistent with other parts of the lease. The above definitions were taken with minor modifications from Alaska's lease.

"Market price" definitions vary from lease to lease and can be quite detailed and lengthy. The following example comes from the U.S. OCS lease:

The value of production for purposes of computing royalty on production from this lease shall never be less than the fair market value of the production. The value of production shall be the estimated reasonable value of the production as determined by the Lessor, due consideration being given to the highest price paid for a part or for a majority of production of like quality in the same field or area, to the price received by the Lessee, to posted prices, to regulated prices, and to other relevant matters. Except when the Lessor, in its discretion, determines not to consider special pricing relief from otherwise applicable Federal regulatory requirements, the value of production for the purposes of computing royalty shall not be deemed to be less than the gross proceeds accruing to the Lessee from the sale thereof. In the absence of good reason to the contrary, value computed on the basis of the highest price paid or offered at the time of production in a fair and open market for the major portion of like-quality products produced and sold from the field or area where the leased area is situated, will be considered to be a reasonable value.

Section 35: Additional or Special Provisions.

[Comment]

Additional provisions might be used to promote various public policy objectives which may or may not be statutorily required. For example, the

United States includes provisions regarding equal opportunity, nonsegregated facilities, and a requirement that twenty percent of the production be offered to small or independent refineries.

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